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Ministre

The Canadian Oil Market

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Canada

THE CANADIAN OIL MARKET

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TABLE OF CONTENTS

CONTENTS **PAGE**

THE CANADIAN OIL MARKET

OVERVIEW

Despite falling oil prices and a strengthening of the Canadian dollar, the domestic oil market, particularly the upstream sector remained strong through the first quarter, continuing a trend which began in the second half of 1987.

Domestic crude oil production was up more than 7%, to 268 000 m^3/d, with more than half the increase in the conventional light crude category. Conventional crude oil capacity proved to be higher than previous forecasts. With fewer restrictions on pipeline transportation, much of the increased production was exported, as total exports jumped more than 20%, to 110 000 m^3/d, and represented about 40% of Canadian crude oil production. The United States continues to be the major market, although offshore deliveries were up 4 500 m^3/d, to 5 000 m^3/d.

Demand by domestic refiners was also strong, reflecting a 5% increase in petroleum product consumption and product export opportunities. Consumption was higher in all regions except British Columbia. Heavy fuel oil demand continued quite strong, reflecting both the growth of the economy and competitive prices relative to substitutes.

Crude oil imports also were up in the first quarter, more than 15% to 73 000 m^3/d, however most of the increase was for export of refined product to the United States under a processing agreement.

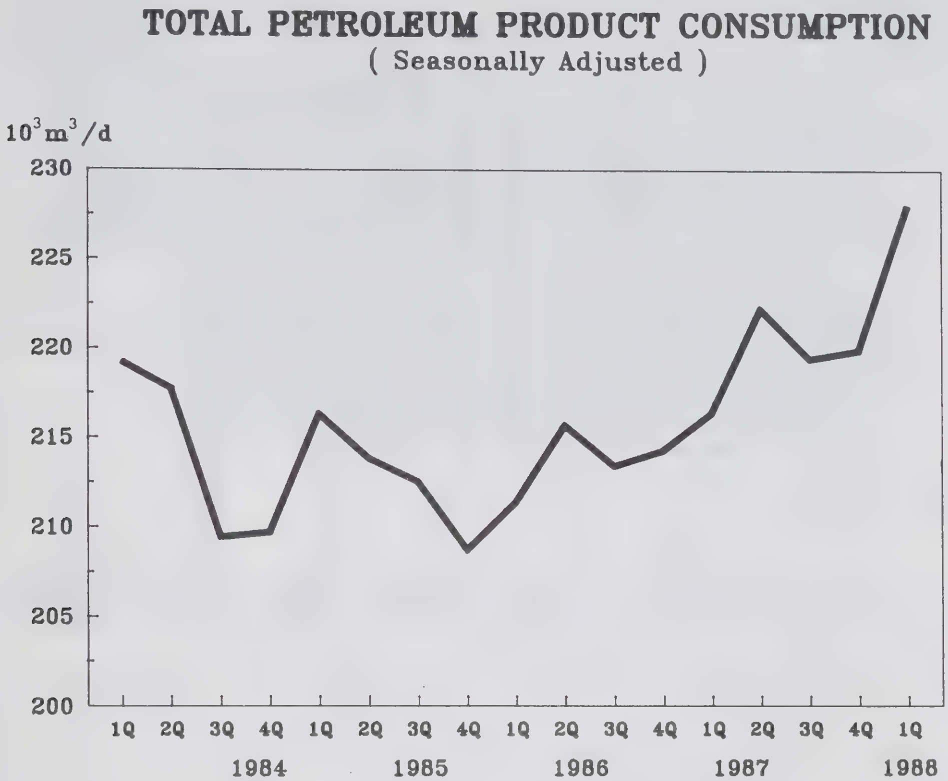
On the negative side, despite the completion of pipeline expansions by Interprovincial Pipe Line (IPL) in 1987, the IPL system is again (marginally) short of capacity, because of higher-than-expected light crude oil supply. Because of the increased supply and strong demand, IPL had to apportion available pipeline space among shippers throughout the first quarter. The situation is not expected to improve significantly over the next year or two. Industry groups are reviewing various courses of action in an attempt to alleviate the problem.

In order to expedite the publication of "The Canadian Oil Market", provisional data for the third month of the quarter under review has been utilized in some cases. In this issue, first quarter data on refinery utilization, crude oil exports (by destination), petroleum product trade, and energy trade balance include provisional March data. Some revisions can be expected in subsequent issues.

THE CANADIAN OIL MARKET

1. Domestic Demand

Seasonally adjusted petroleum product consumption in Canada during the first quarter of 1988 increased to 228 000 m^3/d, up 4% from the previous quarter, and 5% over the average 1987 consumption.



Source: Statistics Canada

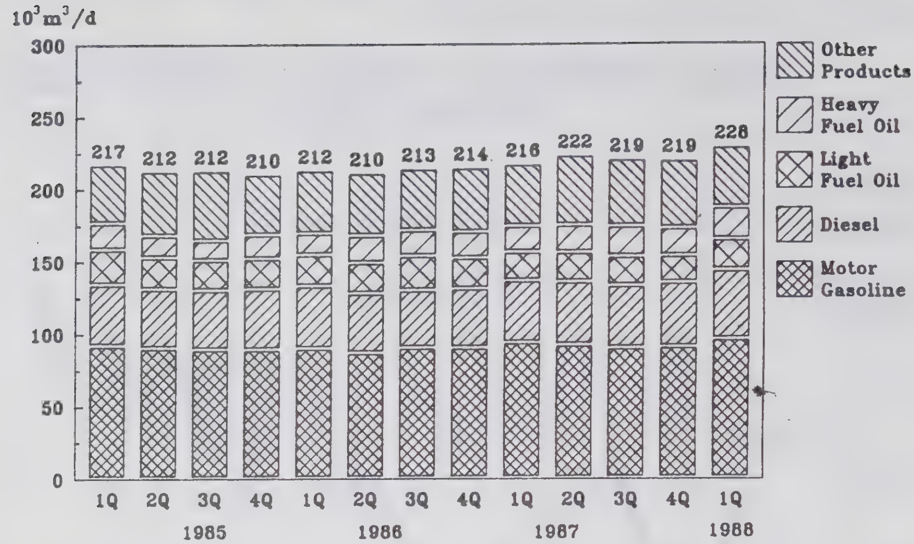
The increase in consumption during the first quarter of 1988 was broadly based over all main products.

In the transportation sector, demand was almost 6% higher at 143 000 m^3/d, with motor gasoline sales increasing 5%, to 96 000 m^3/d and diesel up 7%, to 47 000 m^3/d. In both cases, sales returned to levels recorded during the first quarter of 1987. Diesel fuel use increased considerably in the Prairies due to higher drilling rig activity, although all other regions continued to require additional volumes as well.

Heating oil sales at 21 000 m^3/d were also up sharply with increases in Ontario averaging 15%. Temperatures in eastern Canada, including Ontario, were colder by about 2% in 1988 versus 1987.

Heavy fuel oil gained 14%, for total sales of 22 000 m^3/d, the highest level attained since 1983. As discussed below, the increased use of this product in electricity generation was a major factor in the strong consumption over the last year. Sales of "other products", comprising 20% of total sales, dropped 11% (5 000 m^3/d) to 42 000 m^3/d, partly due to reduced use of petrochemical feedstocks in Ontario. This was a reversal of the upward trend experienced over the last three quarters.

CANADIAN OIL PRODUCT SALES
(Seasonally Adjusted)



Source: Statistics Canada

The largest growth in regional demand occured in the Atlantic region, where domestic sales were up 10% compared with the first quarter of 1987. A large jump in heavy fuel oil demand (up 22%), continued a trend which began in early 1987, accounting for three quarters of the increase in total consumption. In this region, heavy fuel oil now represents 37% of all product demand, reflecting a continued lack of alternative fuels, such as natural gas and a relatively high requirement for heavy fuel oil for electricity generation. In fact, a large part of the heavy fuel oil increase went to generate electricity, as heavy fuel oil prices are again competitive with prices of other forms of electrical generation, such as coal, but with fewer emission problems. The consumption of heavy fuel oil in the Atlantic region (13 000 m^3/d) represented more than half (56%) of the demand for this product in all of Canada.

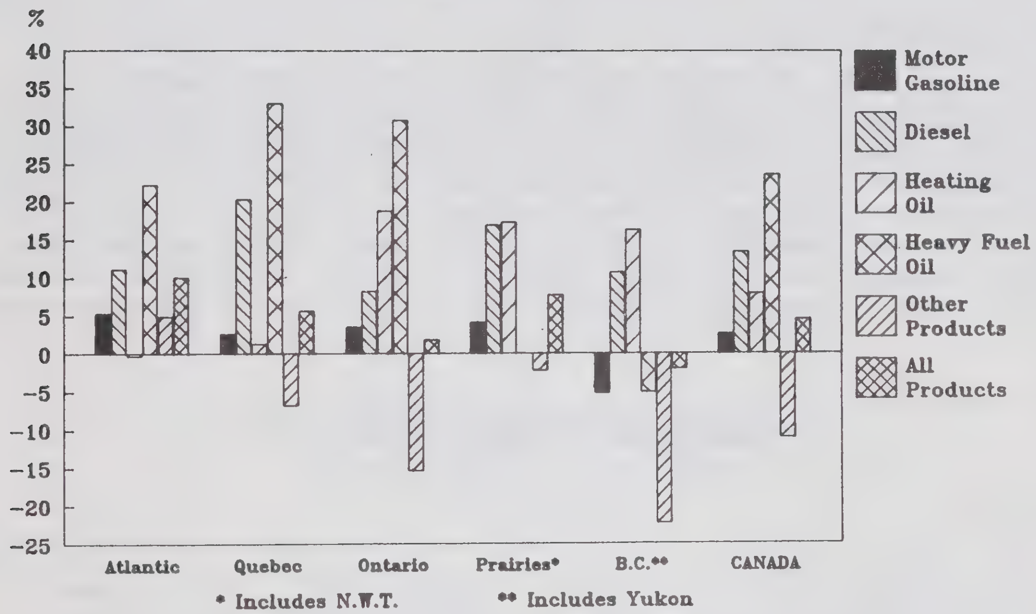
Led by strong gains in heavy fuel oil (33%) and diesel fuel (20%), Quebec sales improved 6% to 49 000 m^3/d. Prices for heavy fuel oil fell over 10% during the first quarter to early 1987 levels. Some substitution for natural gas in industrial use appears to have taken place.

In Ontario, despite an increase in heavy fuel oil sales of 30%, total sales increased only 2% from the first quarter of 1987, as "other products" sales (mainly petrochemical feedstocks) declined 15%. The higher heavy fuel oil demand (over 3 000 m^3/d), was partly due to increased pressure by marketers to convince dual-burning industries to switch to heavy fuel oil by lowering prices to meet, or better, natural gas prices. This change in heavy fuel oil marketing, developed, in part after New York state lowered the sulphur content permitted in heavy fuel oil, contributing to a reduction in Ontario exports of heavy fuel surpluses. As well, in February, interruptible natural gas customers in Ontario had to switch fuel for a week due to delivery problems and a temporary market was opened for the heavy fuel oil.

In the Prairies, a 17% jump in diesel fuel pushed sales to 11 000 m^3/d. This increase was in part attributable to increased drilling rig activity (see Section 11). With increases in the use of the other three main products, the Prairies had the second strongest gain in consumption (up 8%).

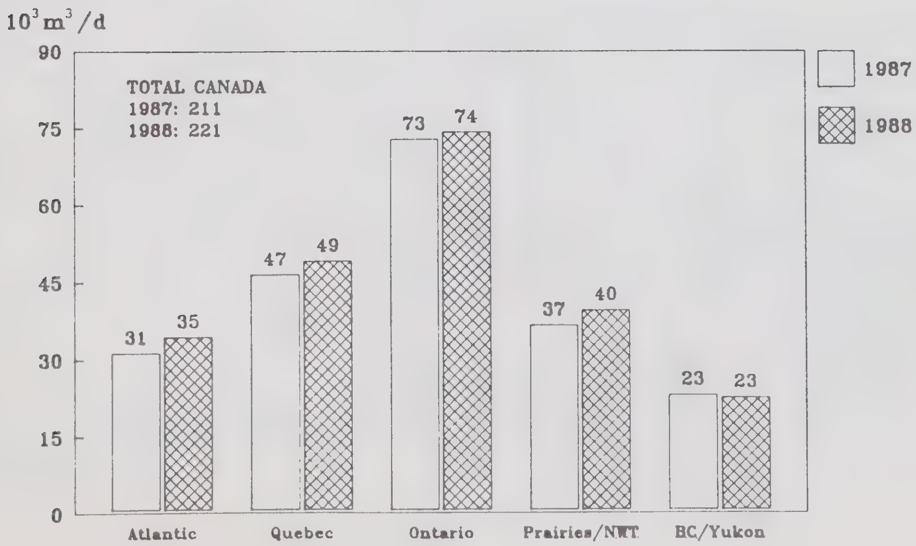
In British Columbia, total consumption of petroleum products was 2% less than in 1987, largely due to a drop in gasoline sales of 5% continuing a pattern which started in the second quarter of 1987.

CANADIAN OIL PRODUCT CONSUMPTION 1988 VS 1987



Source: Statistics Canada

REGIONAL PETROLEUM PRODUCT CONSUMPTION
(First Quarter)



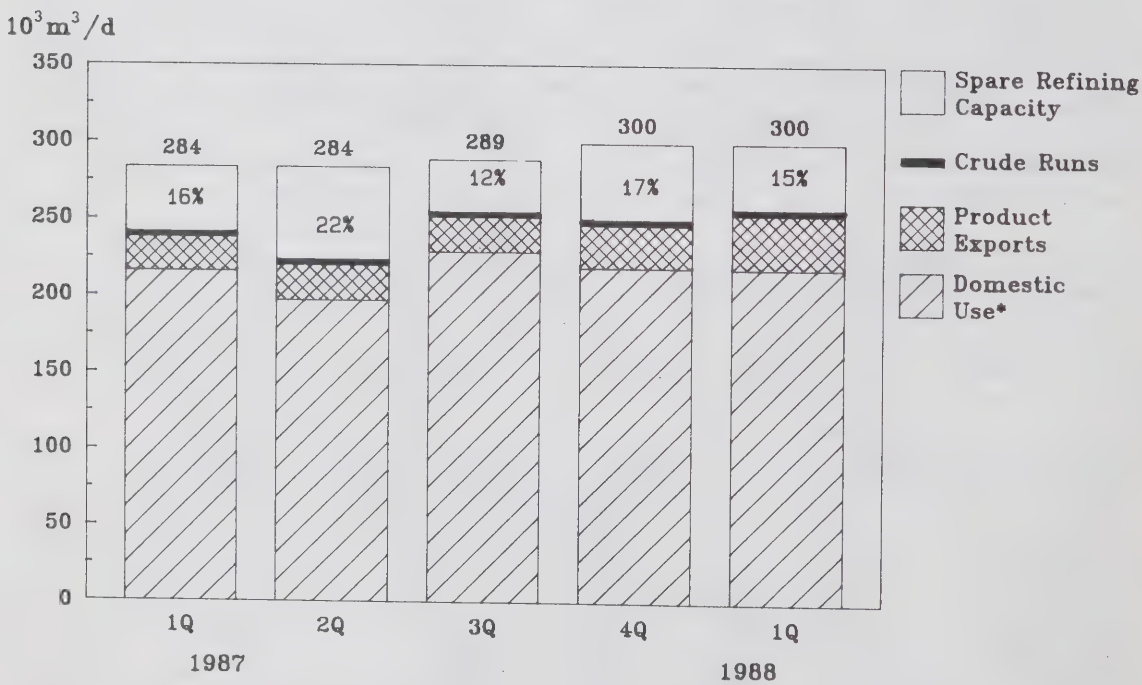
Source: Statistics Canada

On the international level, petroleum product consumption in Canada continued to increase at a faster rate than sales in many other industrialized countries. Preliminary data for the Organization for Economic and Cooperative Development (OECD) countries as a whole indicated less than 2% growth compared with the first quarter of 1987. Canadian demand for petroleum products (up 4.5%) was led by heavy fuel oil and diesel. The year-over-year increase in the United States was similar, at 5%, led by distillate sales up 8%, reflecting colder weather and consumer stock accumulation ahead of a new tax that took effect April 1, 1988. Pacific Rim countries, such as Japan reported a marginal change in total consumption whereas European sales dropped 3% on a year-over-year basis, possibly due to a milder winter compared with 1987.

2. Refinery Utilization

Crude oil run to stills during the first quarter of 1988 jumped by 7%, or 16 000 m^3/d, to 255 000 m^3/d from last year. Almost two-thirds of the increase is related to the reactivation of the Come-by-Chance refinery last September to process crude oil imports and reexport the products to New England. Excluding Come-by-Chance, throughput was up 5 000 m^3/d reflecting higher petroleum product consumption (10 000 m^3/d), and a marginal improvement in petroleum product trade balance, which were partly offset by a much smaller inventory build (difference of 6 000 m^3/d) in comparison with last year.

REFINERY UTILIZATION

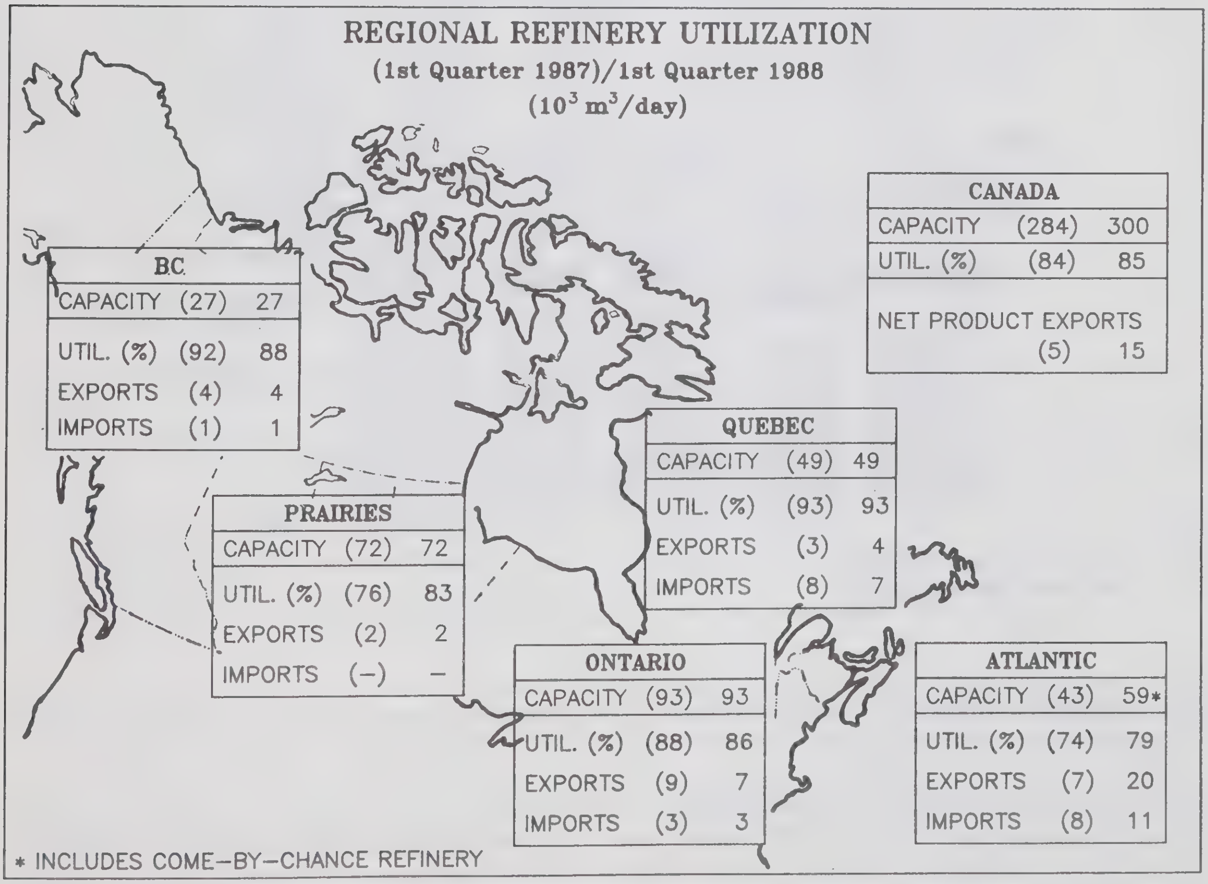


Source: Statistics Canada

* Adjusted for refinery gain

The national refinery utilization rate was approximately 85%, up 1 percentage point from a year ago. With the reactivation of Come-by-Chance, the Atlantic region refining capacity increased by 16 000 m^3/d to 59 000 m^3/d, while all other regions remained unchanged from last year.

The Atlantic region recorded the largest regional increase in crude throughput, up 45% to 46 000 m^3/d, reflecting a 10% increase in petroleum product consumption. (Almost three-quarters of the increase was related to the reactivation of the Come-by-Chance refinery.) Despite increase throughputs, the refinery utilization rate in the Atlantic region remained the lowest at 79%. In Quebec crude use remained virtually unchanged at 46 000 m^3/d (93% utilization), however, consumption rose by almost 6%, and in order to meet the increased demand Quebec refiners drewdown inventories. Ontario throughput fell by 3% to 80 000 m^3/d, in part, reflecting a drop in net petroleum product exports. The Prairies also recorded a strong growth in crude use, up 9% to 59 000 m^3/d largely as a result of an 8% increase in consumption. As in Ontario, throughput in British Columbia declined by 5% to 24 000 m^3/d, because of a drop in petroleum product consumption.



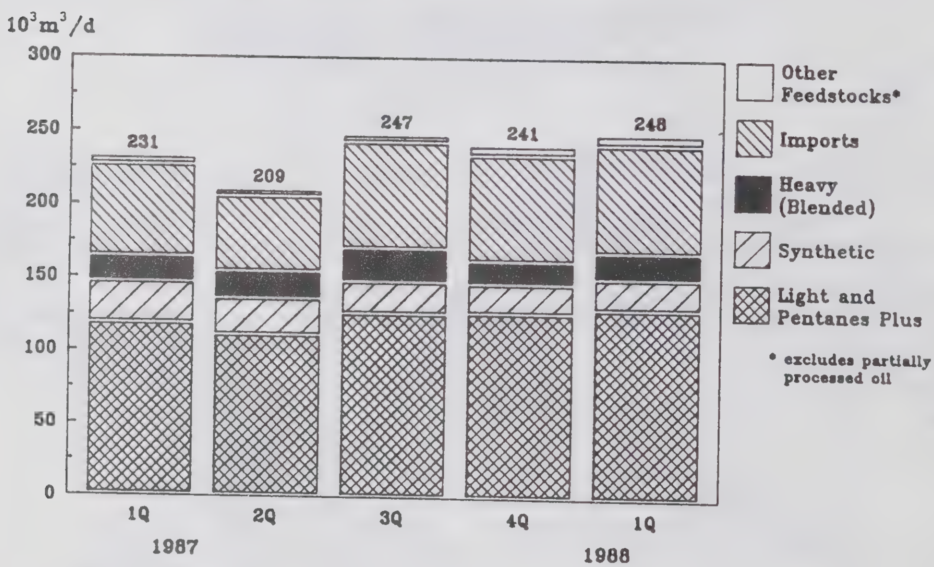
Source: Statistics Canada

3. **Crude Oil Receipts**

Total crude oil deliveries (including gas plant butanes and other feedstocks but excluding partially processed oils) to Canadian refineries during the first quarter of 1988 increased by 8% (17 000 m^3/d, of which more than half was as a result of Come-by-Chance) to 248 000 m^3/d from the same period a year ago. Refiner demand for Canadian crude oil averaged 175 000 m^3/d, an increase of almost 7 000 m^3/d or 4% from last year, which represented the third consecutive quarterly increase. Conventional light crude deliveries rose by 9% (or 10 000 m^3/d) reflecting some substitution for synthetic crude (due to a fire and maintenance at Suncor), higher demand for light products and an inventory build in comparison with last year. Conventional light crude accounted for 61% of total refiner requirements (excluding Atlantic) compared with 57% last year. Heavy crude oil deliveries rose marginally to 18 000 m^3/d.

As a result of the Suncor fire, for the second quarter in a row synthetic crude oil deliveries fell substantially, down to 21 000 m^3/d in comparison with 28 000 m^3/d a year ago. Gross crude oil imports were at 73 000 m^3/d, up 17% (almost 11 000 m^3/d) primarily as a result of the reactivation of the Come-by-Chance refinery.

CRUDE OIL AND EQUIVALENT RECEIPTS AT CANADIAN REFINERIES



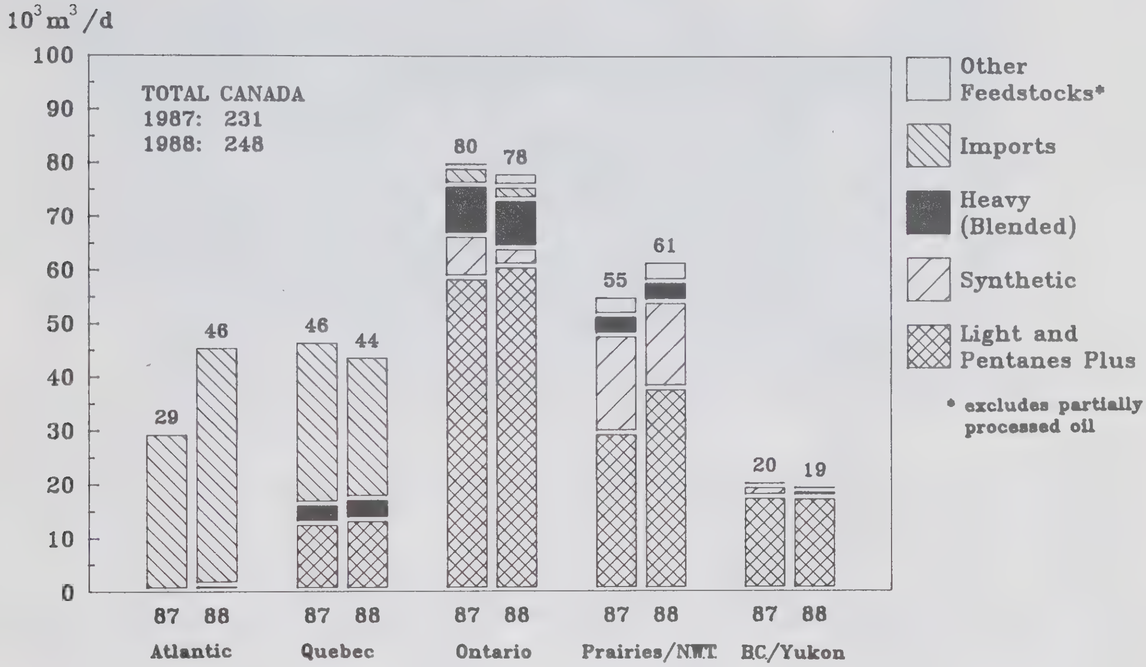
Source: Refiners' submissions to the National Energy Board

On a regional basis, Atlantic crude oil receipts were up 58% to 46 000 m^3/d (see previous section).

Despite an increase in consumption of 6% in Quebec, crude oil receipts fell by almost 3 000 m^3/d, to 44 000 m^3/d. In order to satisfy demand, refiners drewdown product inventories. All of the decline in crude oil receipts occurred in imported crude (down 4 000 m^3/d) while conventional light crude registered an increase of 1 000 m^3/d.

Ontario crude oil receipts also recorded a decline, down 3% to 78 000 m^3/d. The Prairies recorded the largest increase in Canadian crude oil demand, up 12% to 61 000 m^3/d, with all of the increase in conventional light crude oil. Crude oil receipts in British Columbia fell by 3% to 19 000 m^3/d reflecting a decline in consumption.

CRUDE OIL AND EQUIVALENT RECEIPTS BY REGION
(First Quarter)



Source: Refiners' submissions
to the National Energy Board

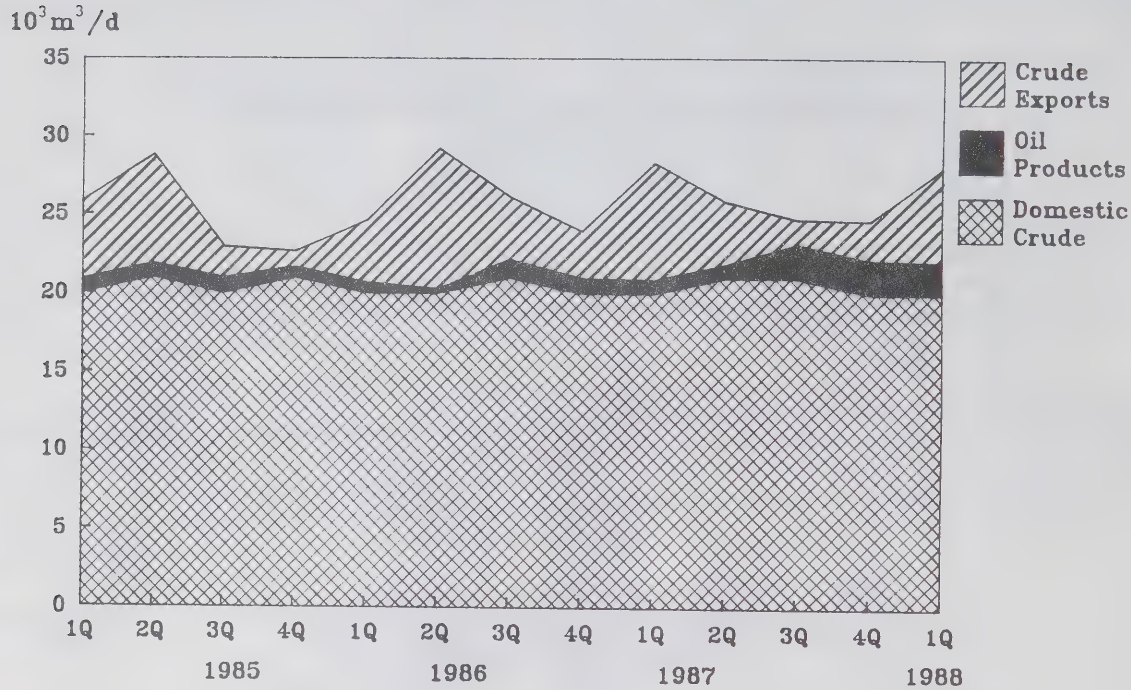
4. Pipelines

4.1 Trans Mountain Pipe Line

Trans Mountain Pipe Line throughput during the first quarter was 27 000 m^3/d, a reduction of 5% from a year ago, but up marginally from the previous quarter. Much of the decline is related to a drop in exports to Washington state, from 4 000 m^3/d to less than 2 000 m^3/d, reflecting better crude prices via the IPL system (whenever the capacity was available). Exports by tanker, however, recorded an increase of 1 500 m^3/d (mainly heavy crude oil) to almost 5 000 m^3/d.

Domestic crude oil deliveries fell by 3% to 19 500 m^3/d (including 4 000 m^3/d of partially processed oil) from a year ago. This decline in crude oil demand was largely attributable to higher product transfers from Alberta, up 1 300 m^3/d to 2 000 m^3/d. Petroleum product movements continued to rise, reflecting a new product terminal at Kamloops, which began operations in July 1987.

TRANS MOUNTAIN PIPE LINE DELIVERIES



Source: Trans Mountain Pipe Line

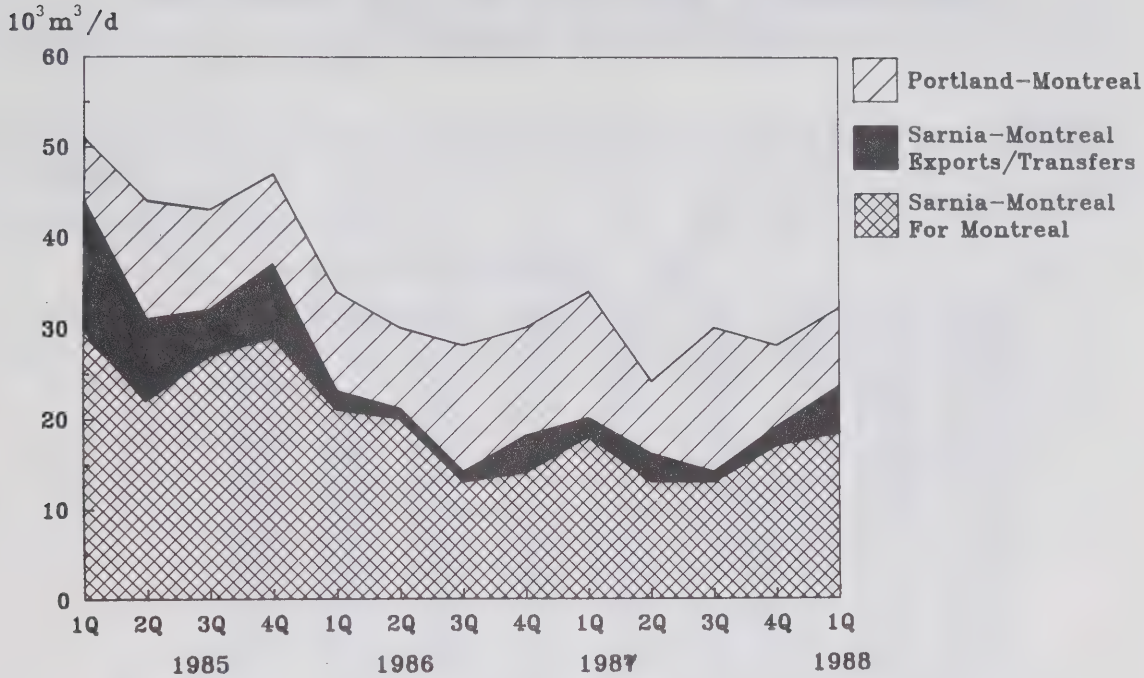
In February, the National Energy Board heard evidence from the oil industry concerning Trans Mountain's application to expand the pipeline to accomodate a forecast increase in heavy crude oil exports and future movements of methyl-tertiary-butyl-ether (MTBE) and petroleum products. The hearings were reopened in April in order to hear evidence from Vancouver-area citizens. A Board decision is expected by the summer.

4.2 Pipelines to Montreal

Total crude oil deliveries to Montreal via IPL's Sarnia-Montreal pipeline and the Portland Pipe Line during the first quarter of 1988 remained unchanged from the same period in the previous two years, at 34 000 m^3/d. The domestic/import mix changed however, as Canadian crude oil deliveries at 23 000 m^3/d, were up more than 3 000 m^3/d, while imports via Portland Pipe Line dropped by 23% (or 3 000 m^3/d) to 11 000 m^3/d. The pipeline utilization rate was 43% for the Sarnia-Montreal link and only 33% for the Portland-Montreal pipeline.

The increase in the Sarnia-Montreal pipeline throughput was directly related to greater heavy crude deliveries for export and domestic transshipments, which doubled to more than 5 000 m^3/d in 1988. Light crude oil deliveries to Montreal refiners fell by more than 1 000 m^3/d to 13 000 m^3/d. Partially processed deliveries remained unchanged at 1 400 m^3/d.

CRUDE OIL DELIVERIES TO MONTREAL



Source: Energy, Mines and Resources
and Interprovincial Pipe Line

Seasonal exports via tanker from Montreal, of mainly heavy crude, have been increasing over the last two years as heavy crude oil output continues to increase and crude oil producers seek market diversification and expansion. The bulk of the exports have occurred in the fall and winter months, counter seasonal to the summer demand peaks in Canada and the U.S. northern tier. First-quarter exports were destined for Europe and the U.S. Gulf Coast.

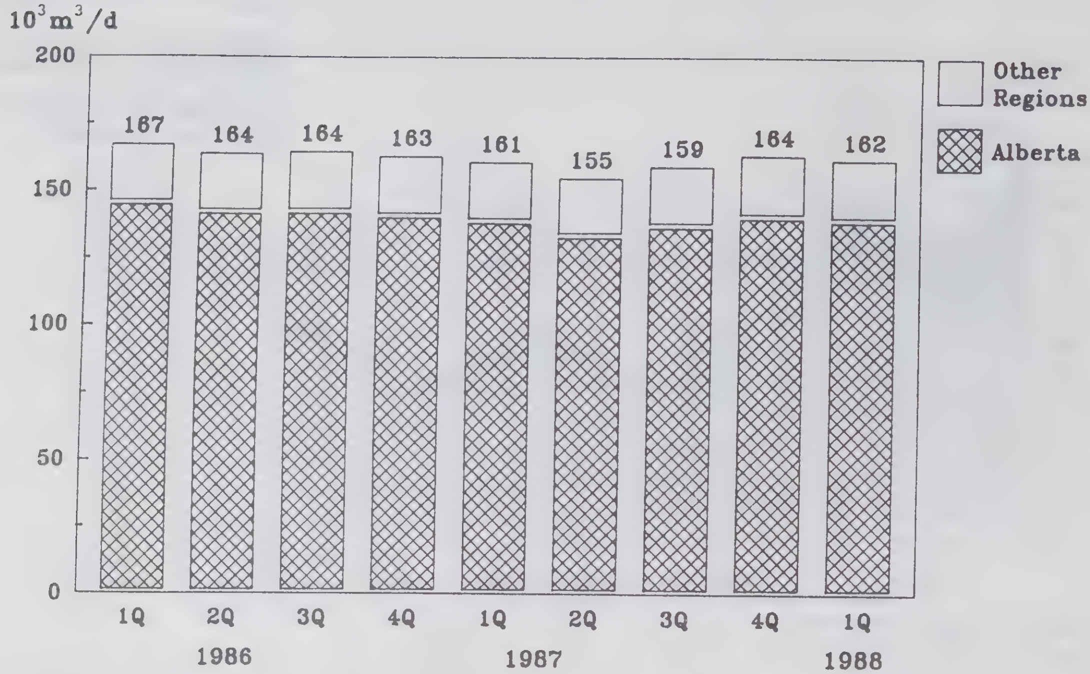
5. Crude Oil Supply and Disposition

5.1 Conventional Light Crude Oil Productive Capacity

Alberta conventional light and medium crude oil productive capacity during the first quarter of 1988 averaged 139 000 m^3/d, up 1 000 m^3/d from a year ago. This increase reflected an increase in drilling activity due to government incentives, enhanced recovery projects and a revision to productive capacity estimates. The completion of IPL phase III expansion and debottlenecking program, combined with the elimination of the prorationing system, allowed Alberta producers to test the real potential of conventional wells in the second half of 1987.

Because of the previously unforeseen incremental light crude production in the second-half, the Alberta Energy Resources Conservation Board, for the second time in a year, revised upward its forecast of conventional Alberta light crude productive capacity. As a result, for the first time since early 1985, Alberta productive capacity in the fourth quarter of 1987 and first quarter of 1988 increased compared with the corresponding period a year earlier.

CONVENTIONAL LIGHT AND MEDIUM CRUDE OIL PRODUCTIVE CAPACITY



Source: National Energy Board

Conventional light crude capacity, including 23 000 m^3/d produced in other regions, totalled 162 000 m^3/d, represented 60% of Canadian crude oil productive capacity, and about 80% of total available light crude supply.

5.2 Light Crude Production and Disposition

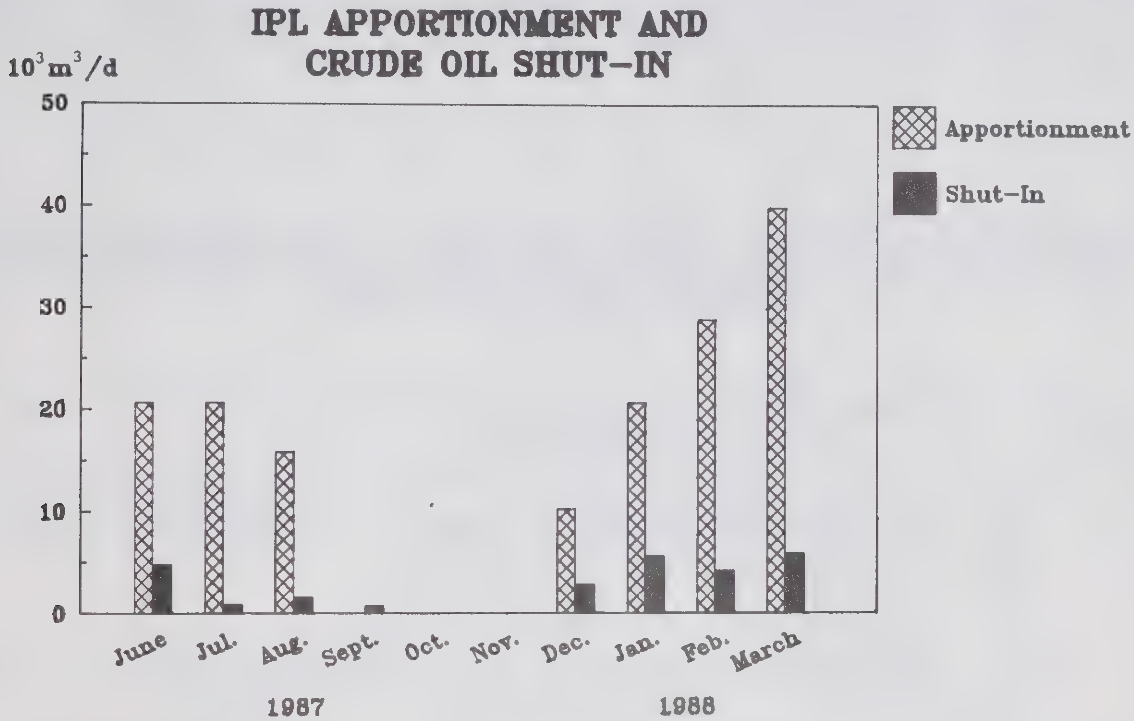
Although some pipeline constraints reduced potential crude oil production during the first quarter of 1988, the shortfall was much less than for the same period a year earlier. As a result, total light oil production (excluding pentanes plus as diluent) was 6% (10 000 m^3/d) higher, reaching 190 000 m^3/d. The 1987 expansion to the IPL system and introduction of the modified prorationing system contributed to the higher production level and commensurate drop in shut-in capacity. Light crude shut-in fell 80% (16 000 m^3/d).

During the first quarter of 1988, Alberta's conventional light crude production increased 14% (17 000 m^3/d), to 135 000 m^3/d, leaving only 4 000 m^3/d of crude shut-in compared with 20 000 m^3/d last year. Production of conventional light crude in other provinces remained unchanged at 23 000 m^3/d.

Completion of the IPL expansion in mid-1987 allowed producers relatively uninterrupted access to their customers, while at the same time demand increased, particularly in the export market. The increase in light crude productive capacity was greater than industry expectations. By the first quarter of 1988, IPL was once again short of the pipeline capacity required to move the volume desired by shippers on that system.

Given "expected" shipments via the Trans Mountain and Rangeland pipeline systems, and demand by refiners in Edmonton, Alberta, the IPL system will probably be short of capacity by about 4 to 6 000 m³/d on an ongoing basis through much of 1988 and early 1989.

Throughout the first quarter, refiner nominations for Canadian crude oil exceeded IPL capacity to move crude to eastern Canada and the United States by 15 to 20% per month. As a result, IPL had to apportion the available pipeline space among the shippers.



Source: Energy, Mines and Resources /
National Energy Board

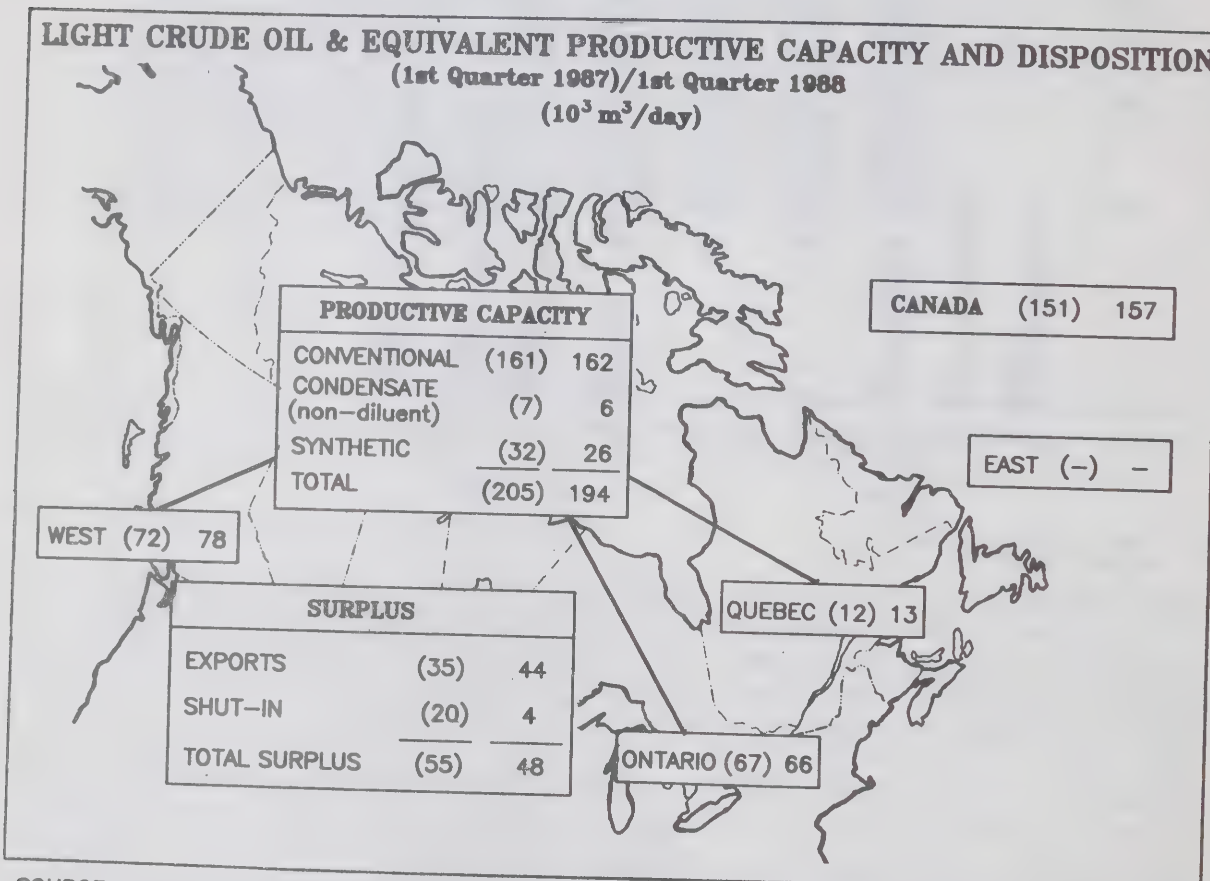
Various industry and government committees are monitoring the logistics of oil production and transportation to ensure that pipeline space is allocated on an equitable basis. The committees are trying to resolve this problem in addition to reviewing various courses of action with respect to the current pipeline capacity shortfall.

In order to maintain production levels, companies increased movements through the Trans Mountain and Rangeland systems. The spot sales, however, were generally at discounts to those through the IPL system. Throughout most of the first quarter, Trans Mountain was operating at close to full capacity, while there was about 2 to 3 000 m³/d of excess capacity on Rangeland.

Synthetic crude oil production was 26 000 m³/d, down 18% (6 000 m³/d) from the first quarter of 1987. This production level was still relatively high, considering that Suncor did not resume operation until late January and that part of the Syncrude plant underwent maintenance in January. Total March synthetic production at over 33 000 m³/d, was near record levels.

Pentanes production at 19 000 m³/d was 4% higher than in 1987. The volume available for refinery use was down 1 000 m³/d to 6 000 m³/d, however, the demand for pentanes as heavy crude diluent continues to exceed incremental supply increases.

The increased light and equivalent crude production was split between both domestic and export markets. (There was also a drawdown of crude oil inventories at field and major pipelines in order to meet refiner demand.) Refiners in Alberta and Saskatchewan took an additional 7 000 m³/d of light crude, while deliveries to other regions were basically unchanged. Export market deliveries were up an additional 9 000 m³/d to 44 000 m³/d, a 26% increase over the first quarter of 1987.



SOURCE: National Energy Board

Note: Difference between productive capacity and disposition can be attributed to stock change.

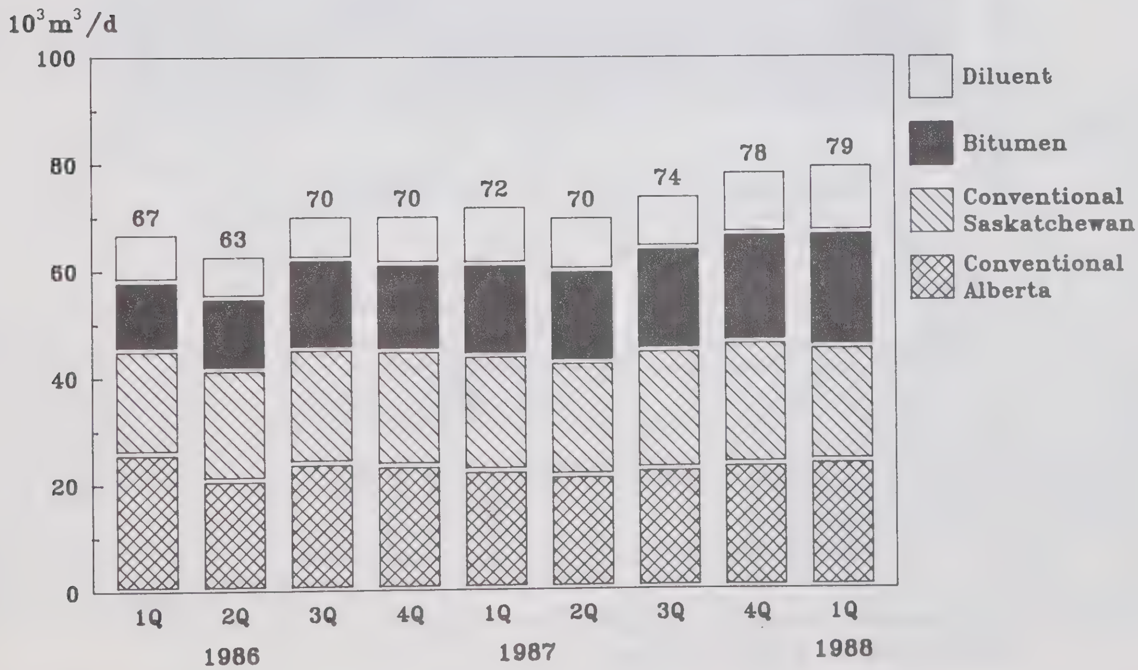
5.3 Heavy Crude Oil Productive Capacity

Unblended conventional heavy crude oil productive capacity during the first quarter of 1988 averaged around 45 000 m³/d, up almost 1 000 m³/d from the level of last year. Both conventional heavy crude and bitumen capacity remained static or declined marginally in the last half of 1986 and early 1987 reflecting, in part, the impact of the price decline in early 1986 and a pessimistic price outlook. In the latter half of 1987, because of more stable crude prices, a more optimistic price outlook and higher drilling activity, in particular for conventional crude in the Bow River area, productive capacity rose.

Although the growth in conventional heavy crude capacity during the last three years has been relatively low and erratic in comparison with bitumen, most of the additional capacity has been added in Alberta, where much of the future resource base lies. In 1985, conventional capacity from Saskatchewan accounted for 51% of total conventional supply of 41 000 m³/d. By the first quarter of 1988, the Saskatchewan portion had declined to 47% of 45 000 m³/d, with Alberta accounting for the remaining 53%.

"Neat" bitumen productive capacity was up by 4 000 m³/d, or 23%, to 21 000 m³/d reflecting the completion of several projects. With the increase in bitumen supply, diluent requirements increased by almost 2 000 m³/d to 13 000 m³/d. Total blended heavy crude oil productive capacity averaged 79 000 m³/d, up 7 000 m³/d from a year ago. This volume represents the highest-ever productive capacity level for heavy crudes.

HEAVY CRUDE OIL PRODUCTIVE CAPACITY



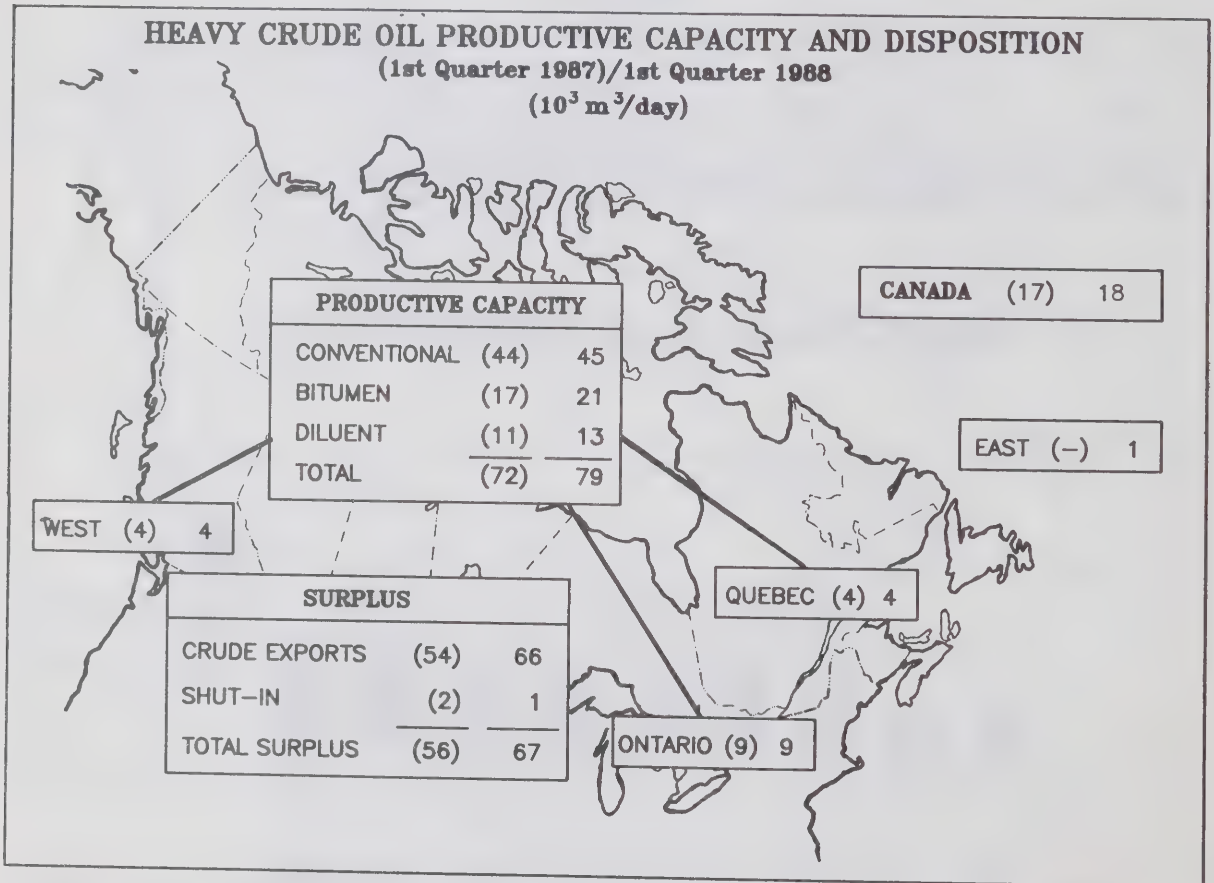
Source: National Energy Board

5.4 Heavy Crude Production and Disposition

In the heavy crude category, blended production reached 79 000 m³/d, a 10% (8 000 m³/d) increase over the previous year. Conventional heavy crude was up 3% (1 000 m³/d) to 45 000 m³/d. The largest increases in production continued to be in bitumen, and in the requirements for pentanes plus as diluent. Bitumen output of almost 21 000 m³/d (up 4 000 m³/d) set a new output record, as did the diluent requirements of 13 000 m³/d (a 18% increase). The shut-in of heavy crude amounted to slightly more than 1 000 m³/d, about the same as in 1987.

Domestic deliveries of heavy crude were marginally higher at almost 18 000 m³/d. The market expanded eastward however as Atlantic region receipts were up 1 000 m³/d, from nil in the first quarter of 1987.

Most of the incremental production was exported. Total exports were 66 000 m³/d, a 25% increase over 1987. (See Section 6 for further discussions on exports)



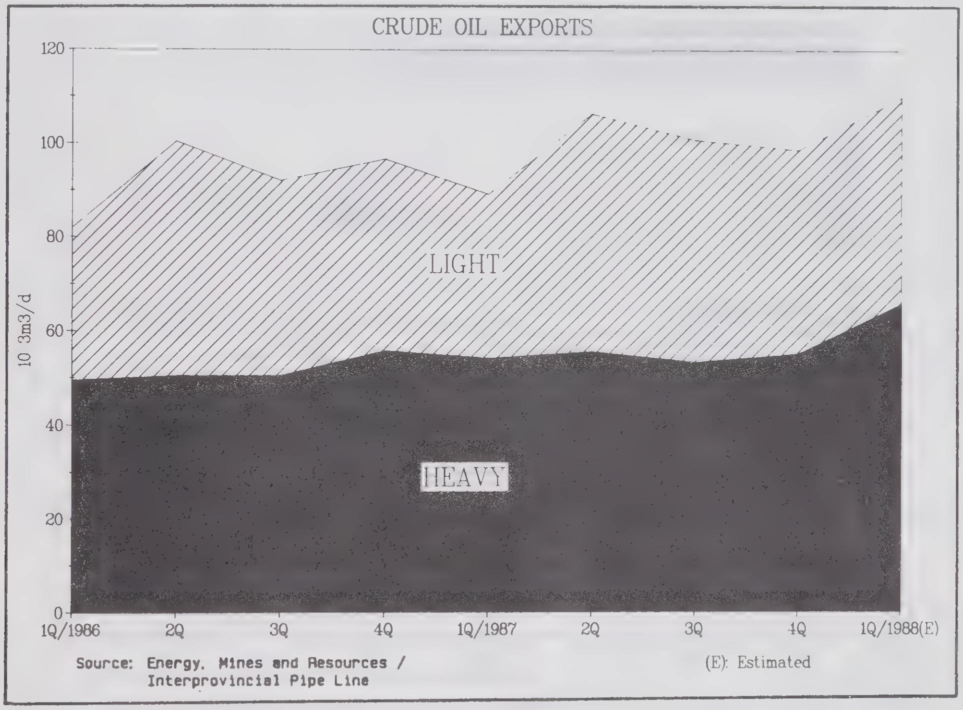
SOURCE: National Energy Board

Note: Difference between productive capacity and disposition can be attributed to stock change.

6. Exports and Imports

6.1 Crude Oil Exports

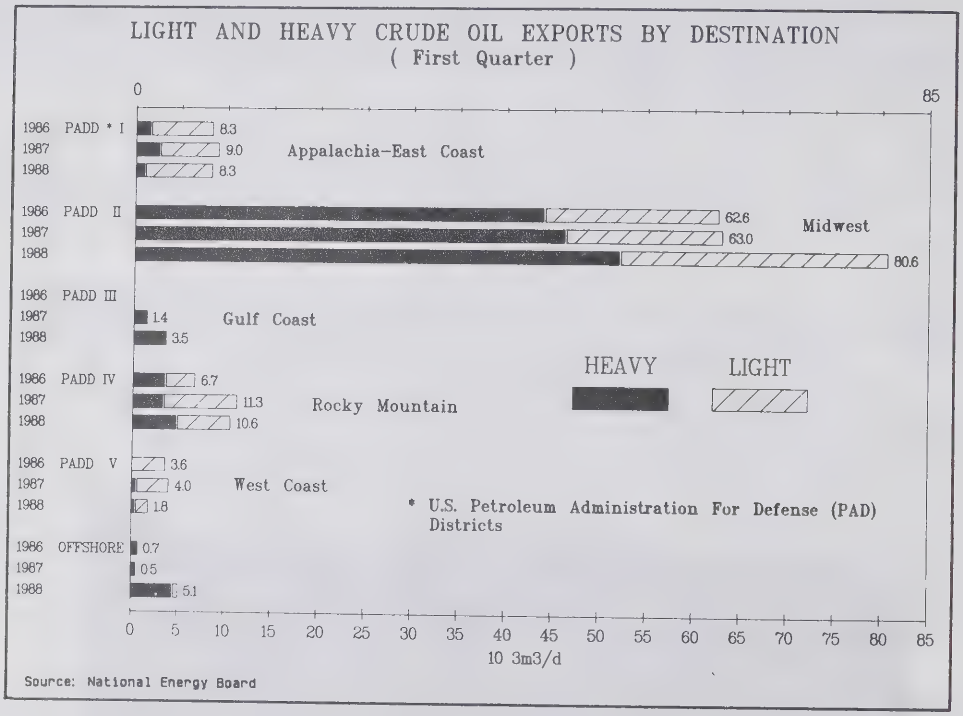
Crude oil exports for the first quarter of this year were more than 110 000 m^3/d, an increase of 21 000 m^3/d (23%) from the same period a year earlier. The additional exports, which reflected in part, greater U.S. demand, increased pipeline capacity and Alberta's modified prorationing system, were split at a ratio of 60/40 between heavy and light crudes. Heavy crude exports increased by 21%, to 66 000 m^3/d, while light and equivalent crudes increased by 26%, to 44 000 m^3/d. Overall, total Canadian exports of crude represented about 40% of domestic crude production, 8 percentage points higher than the previous year (heavy exports, 84% of production, light exports, 22%).



Exports of crude oil to the United States, including deliveries through the ports of Montreal and Vancouver, totalled 105 000 m^3/d, an increase of 16 000 m^3/d (18%) from a year earlier. This volume includes 103 000 m^3/d which was destined for points east of the Rocky Mountain to Petroleum Administration for Defense (PAD) Districts I-IV* while the remainder moved west to District V. In addition, offshore exports increased dramatically (4 500 m^3/d) on small volumes, to 5 000 m^3/d. Mainly heavy crude was tankered to primarily Far East destinations including Japan, Malaysia, Taiwan, and Thailand, and to Holland as producers continued their pursuit of market diversification.

* See Appendix I for a complete geographic description.

As in the past, PAD District II receipts accounted for the largest share of Canadian pipeline-connected crude exports. First quarter of 1988 receipts averaged 81 000 m^3/d, about 77% of all Canadian exports of crude to the United States, up 6 percentage points from the previous year. Heavy crude receipts, because of incremental bitumen production, increased by 13%, to 52 000 m^3/d, while light crude receipts helped by declining U.S. indigenous production, increased product demand and increased pipeline capacity jumped by 70% to 29 000 m^3/d.



Most of the PAD District II increase was registered in the Chicago, Illinois refining market where heavy crude receipts increased by 22% to 24 000 m^3/d, and light by 66%, to 17 000 m^3/d. Other major refining centres within the PAD, the Twin Cities area of Minnesota and the Toledo-Detroit area of Ohio and Michigan, doubled their take of light crude to 3 and 8 000 m^3/d, respectively, while heavy receipts increased marginally from last year, to about 26 and 2 000 m^3/d.

While exports to PAD District II increased, exports to Districts IV and V declined somewhat, reflecting increased transportation capacity for eastern movements, and relatively higher producer netbacks on sales into the U.S. midwest.

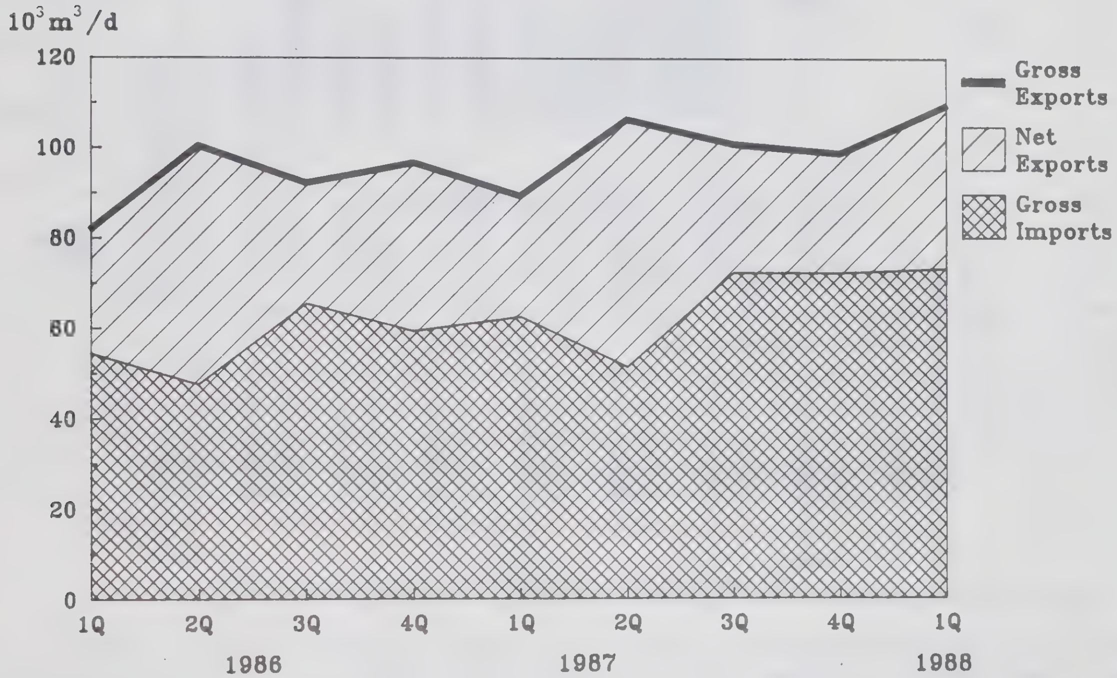
In 1987, the Wascana Pipe Line (capacity of about 8 000 m^3/d) was reopened and marginal volumes of crude were exported from Saskatchewan to Montana (District IV), eventually reaching Wyoming. In the first quarter of 1988 exports continued, but at low volumes (less than 1 000 m^3/d).

Traditional refinery turnaround early in the spring to adjust for product mix change to supply summer requirements and IPL capacity rationing could reduce total crude exports, in particular, to pipeline-connected PAD District II during the second quarter of this year, compared with the first quarter.

6.2 Crude Oil Imports

Gross crude oil imports during the first quarter of 1988 averaged 73 000 m^3/d, up 17% from a year ago, however, virtually all this increase reflected requirements for the Come-by-Chance refinery. Oil import dependence in Canada expressed as a percentage of domestic consumption, declined marginally by 1 percentage point to 27%.

CRUDE OIL EXPORTS AND IMPORTS



Source: National Energy Board

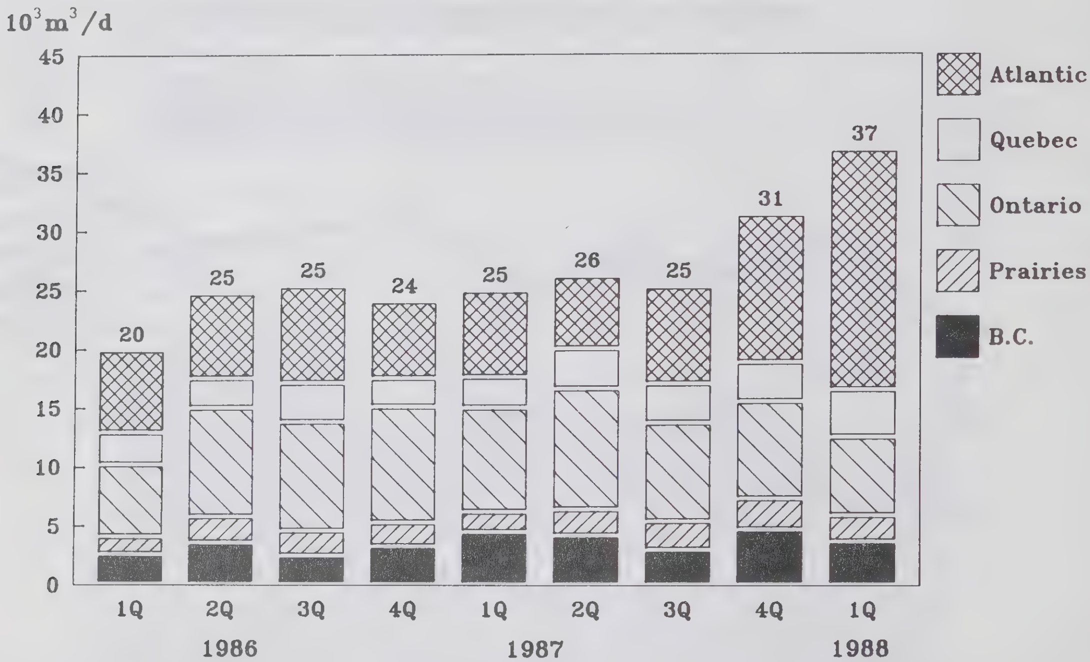
6.3 Petroleum Product Trade

In contrast to the fourth quarter of 1987 when imports were sharply higher, it was product exports that increased substantially during the first quarter of 1988. As a result, the net petroleum product surplus jumped to 15 000 m^3/d from 4 000 m^3/d during the same quarter of 1987. This was largely because of the Come-by-Chance processing agreement under which most of the oil production is exported. Little change was recorded in import volumes. Except for Quebec, exports exceeded imports in all regions, with the Atlantic surplus the largest, at 10 000 m^3/d.

Gross product exports totalled 37 000 m^3/d, 12 000 m^3/d higher than in 1987. Virtually all of the increase occurred in the Atlantic region, where exports jumped 13 000 m^3/d, to 20 000 m^3/d. Exports now account for almost 45% of refinery throughput in the Atlantic region.

In Quebec, exports rose 60% or 1 500 m^3/d with heavy fuel oil accounting for two-thirds of the increment. Deliveries of products out of Ontario dropped 2 000 m^3/d (23%), reflecting the effect of a more stringent New York State emission standard, which reduced potential heavy fuel oil exports from Ontario. British Columbia exports dropped marginally to under 4 000 m^3/d, despite additional volumes being shipped to Japan. There was a decline in volumes usually delivered to the northwestern United States.

GROSS REGIONAL PETROLEUM PRODUCT EXPORTS



Source: Statistics Canada

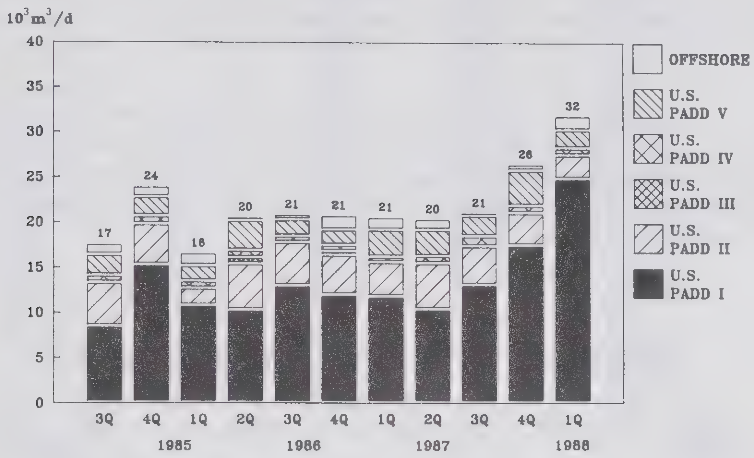
Sales to the United States continued to make up about 95% of Canadian main petroleum product exports. Deliveries into PAD District I, particularly to states adjacent to Canada in the northeastern U.S., accounted for 80% of the U.S. total, compared with 60% in the first quarter of 1987. This reflected increased receipts from the Newfoundland processing agreement.

Virtually all of the remaining exports (1 600 m^3/d) went to Japan from British Columbia. Sales to Japan have been gradually increasing since that country relaxed its product import restrictions in 1986.

While the United States was easily Canada's largest market for product exports, Canadian product (excluding liquefied petroleum gases) exports to the U.S. represented only 8% of that country's total receipts of foreign refined products during the first quarter.

Product imports by the United States were 325 000 m³/d in the first-quarter. Venezuela was the largest supplier with 20% of U.S. imports, followed by the Virgin Islands, Algeria and Canada. Canadian sales were more significant on a regional basis, accounting for all of the U.S. import requirements in PAD District IV, albeit a small volume (800 m³/d) and 40% of PAD District V imports.

MAIN PETROLEUM PRODUCT EXPORTS BY DESTINATION*

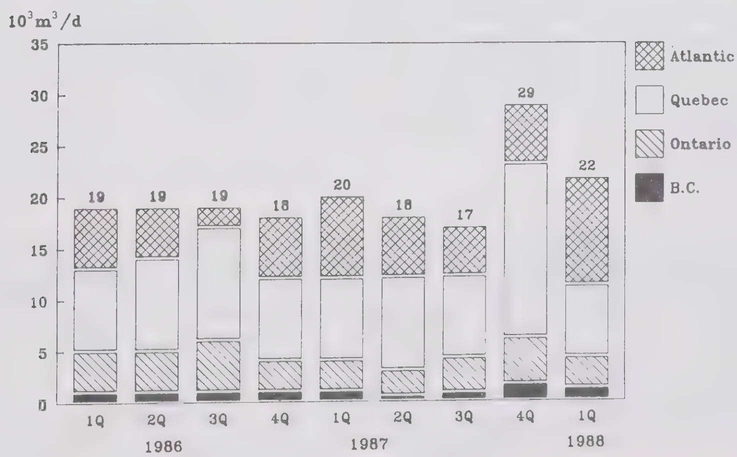


Source: National Energy Board

* excludes some products e.g. lubricants included under Statistics Canada definition

Gross imports of 22 000 m³/d were 2 000 m³/d higher than in 1987. The Atlantic had the highest total volume imported (11 000 m³/d) and the largest increase on a year over year basis (39%). Almost 80% of the imports were heavy fuel oil reflecting increased demand. (see Section 1) Quebec receipts dropped 1 000 m³/d, to 7 000 m³/d, whereas other regions were virtually unchanged. Products were imported from a number of countries including Argentina, Great Britain, Spain, the United States, and Venezuela.

GROSS REGIONAL PETROLEUM PRODUCT IMPORTS



Source: Statistics Canada

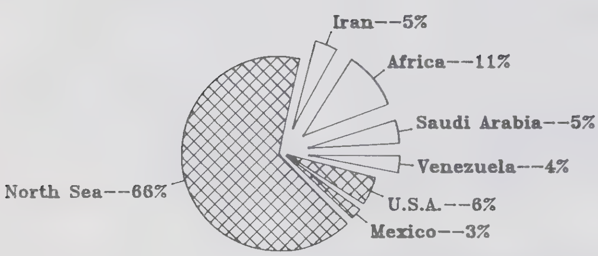
7. Composition of Crude Oil Imports

Despite a small increase in volumetric terms, to 16 000 m³/d, OPEC's market share of the Canadian import market fell by 3 percentage points to 22%. The composition also changed from a year ago. Imports from Iran, which averaged 3 000 m³/d in 1987, fell to zero during the first quarter of 1988. Imports from Venezuela and "other Middle East countries" (e.g. Iraq) recorded the largest increase, both up around 1 500 m³/d, to 4 000 m³/d and 1 500 m³/d, respectively. Saudi Arabia imports remained unchanged at around 3 000 m³/d. African countries remained the largest exporters of crude oil to Canada among OPEC members, at 8 000 m³/d, or 50% of OPEC's exports to Canada.

The major source of supply is still the North Sea, accounting for 72% of crude oil imports, up 6 percentage points from a year ago. Most of this increase resulted from Come-by-Chance imports. In contrast, imports from the United States dropped by 40% to 2 300 m³/d, and imports from Mexico fell from 2 000 m³/d to less than 1 000 m³/d.

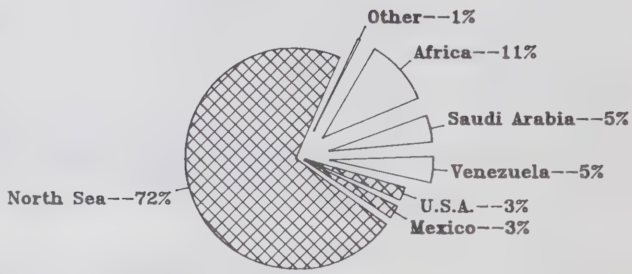
SOURCES OF CRUDE OIL IMPORTS
(First Quarter)

1987



TOTAL 63 $10^3 m^3/d$
Non-OPEC 75% OPEC 25%

1988



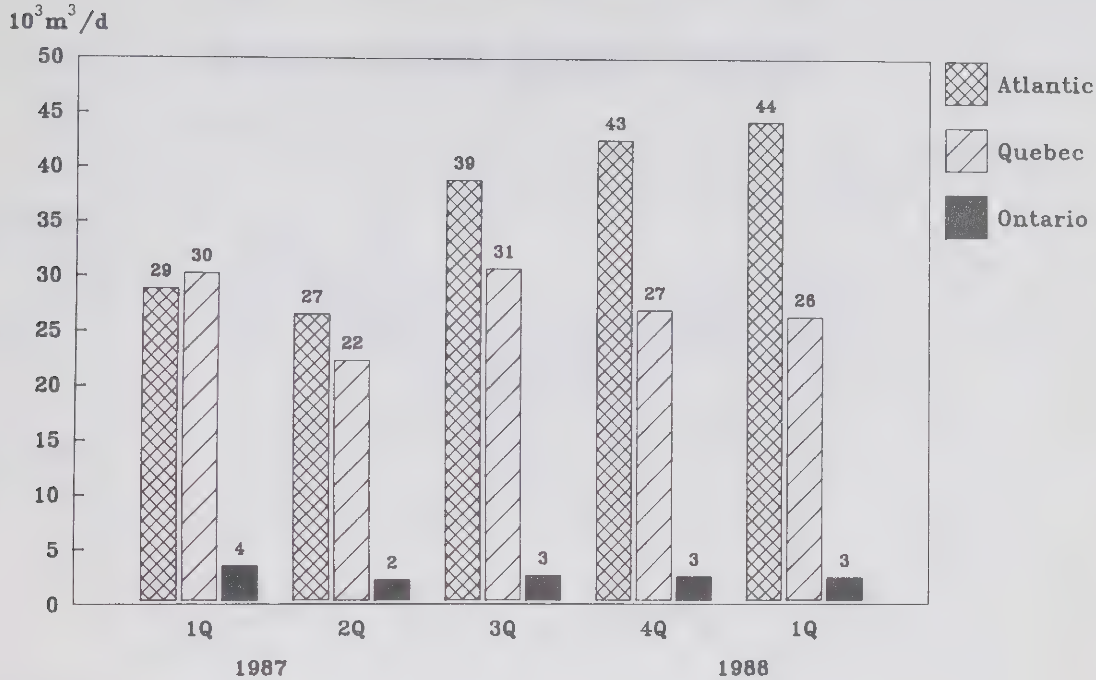
TOTAL 73 $10^3 m^3/d$
Non-OPEC 78% OPEC 22%

Source: National Energy Board

On a regional basis, imports jumped by 53% to 44 000 m³/d in the Atlantic region, largely attributable to the imports into Newfoundland. (Excluding the Come-by-Chance, imports would have increased by 19% to 34 000 m³/d.)

Imports into Quebec and Ontario dropped by 13% and 24%, to 26 000 m³/d and 2 500 m³/d respectively, reflecting some substitution of imported for domestic crude oil and, in Quebec, a drawdown of product stocks.

CRUDE OIL IMPORTS BY REGION



Source: Refiners' submissions to the National Energy Board

8. Energy Trade Balance

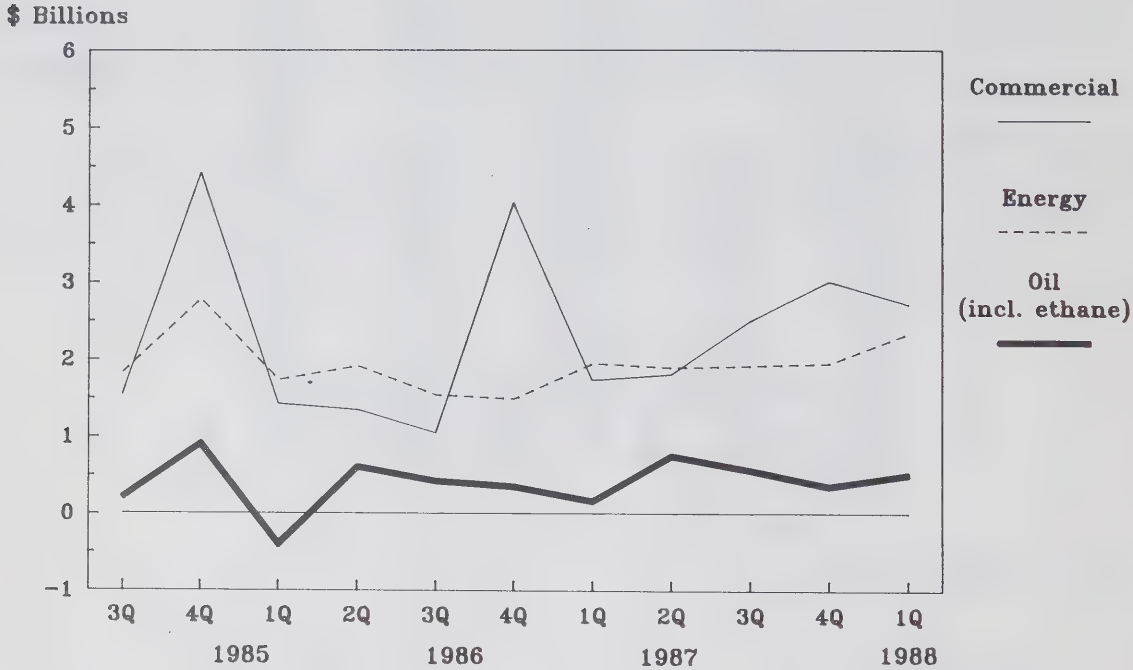
8.1 International

Based on preliminary data from Statistics Canada, Canadian energy trade for the first quarter of 1988 resulted in an estimated surplus of over $2.3 billion, $400 million higher than for the same period in 1987. Natural gas made the largest contribution with first-quarter net exports worth almost $1.0 billion, a third higher than in 1987. Exports of petroleum, which is composed of crude and petroleum products, also increased, resulting in a net surplus of over $300 million. Improvements in natural gas and oil trade accounted for the increase in the energy surplus, as coal, electricity and uranium all registered small declines.

To a large extent, the higher surplus reflected increased sales, rather than higher prices. First-quarter exports of natural gas and crude were substantially higher than in recent years (see Section 6 for crude exports), in part, because of increased transportation (oil) capacity, supply shortfalls and strong demand in Canada's main market, the United States. The higher crude exports were matched to a certain extent by greater imports. Most of the higher imports were reexported as refined products however, thus having a neutral impact on trade.

The oil share of the overall commercial trade balance increased from 8% to 10% as compared with the same period last year. However, the impact of total energy on the overall surplus was greatly reduced from a year ago when it accounted for about 115% as compared with 85% in 1988.

OIL AND ENERGY TRADE BALANCE



Source: Statistics Canada

8.2 United States

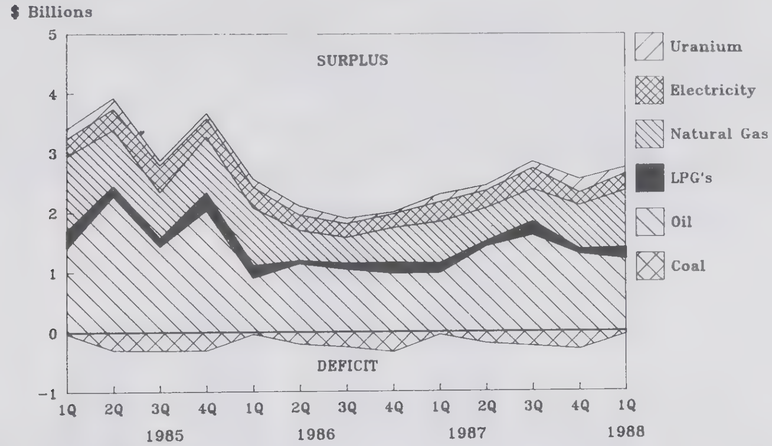
The increase in the total energy trade surplus was almost entirely attributed to transactions with the United States (which accounted for 80% of our exports) as the Canadian energy surplus with the United States was $2.5 billion for the first-quarter, $300 million higher than a year ago.

Higher crude oil and natural gas exports were the primary reason why the surplus increased. Crude oil exports were worth an estimated $1 billion to Canadian producers, $150 million higher than in 1987, despite lower crude prices and the stronger Canadian dollar. (see Section 10). Crude oil and petroleum products continued to account for the largest part of the trade surplus with the United States, although over the last year natural gas trade (all exports) improved significantly. Natural gas accounted for more than 38%, and crude oil and petroleum products for 43% of the surplus in 1988, compared with 31% and 44%, respectively, in the first quarter of 1987.

During the first quarter, the overall trade surplus with the United States grew much faster on a volumetric basis (up 40%) than on a value basis, reflecting sliding prices received over the quarter.

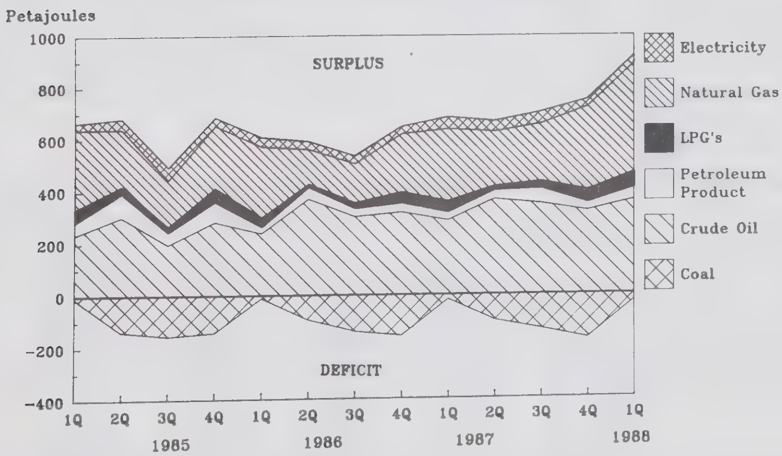
Canada continued to have a trade deficit in coal with the United States, however on a seasonal basis the deficit remained the lowest in the first quarter (at less than $20 million in 1988).

NET ENERGY COMMODITY TRADE WITH THE U.S. (VALUE)



Source: Statistics Canada

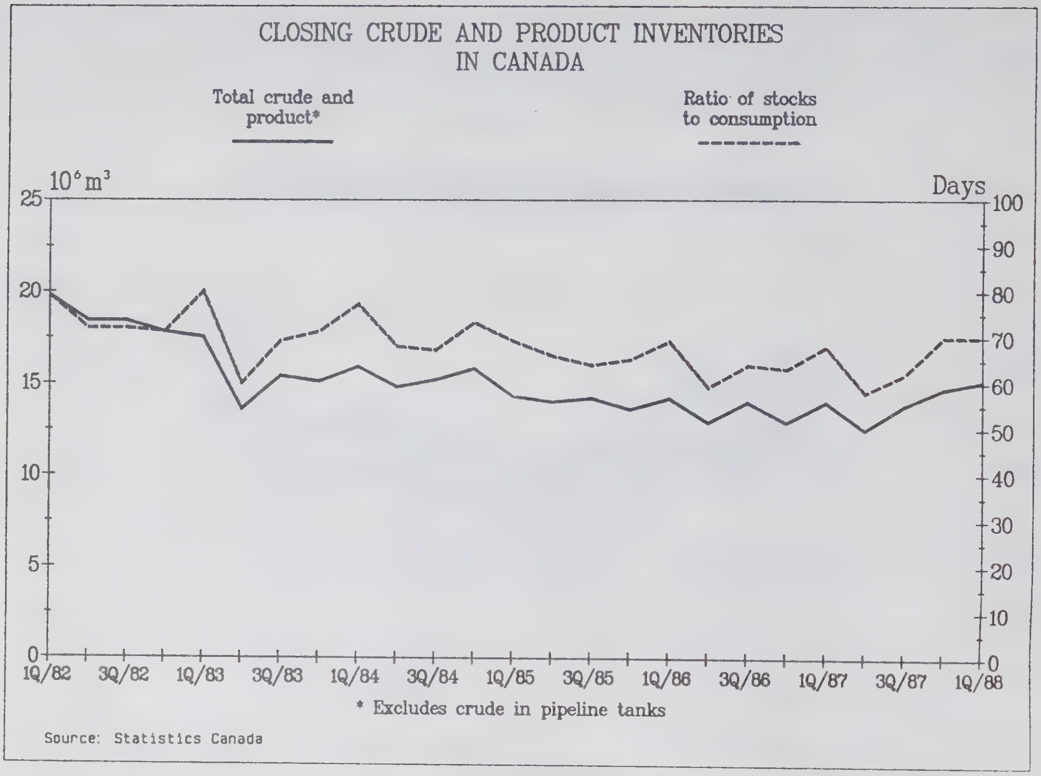
NET ENERGY COMMODITY TRADE WITH THE U.S. (VOLUME)



Source: Statistics Canada

9. Stocks

Refined product and crude oil inventories at the end of the first quarter were 15 million cubic metres, an 8% increase from a year earlier. Product stocks were higher by 5%, at 12 million cubic metres, while crude inventories increased to almost 3 million cubic metres, or 20%.



The increase in crude stocks was primarily the result of a doubling of crude inventories in the Atlantic region, to 1.4 million cubic metres. Part of the increase may be attributable to fluctuations in crude delivery (ship versus pipeline) which may lead to sharp variations in crude stock levels. The startup of the Newfoundland refinery also contributed to about one quarter of the increase. A decline of about 25% in Quebec offset some of the Atlantic increase.

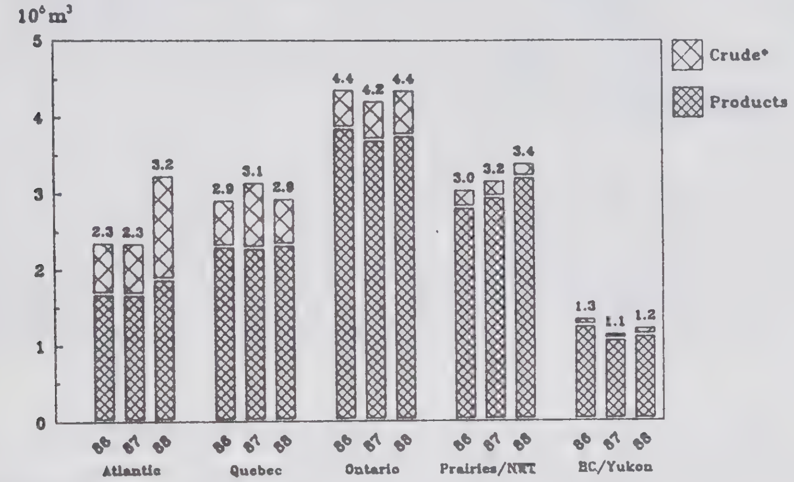
In petroleum products, heating oil was the only main product to register a decline, down 15%, reflecting continued rationalization and colder weather than normal in eastern Canada. All other product stocks rose, with heavy fuel oil posting the largest increase both in volumetric and percentage terms. The end-March inventory of 975 thousand cubic metres was 350 thousand cubic metres or 55% larger than in 1987, because of higher stocks in the Atlantic, Quebec and Ontario needed to meet the continuing demand for heavy fuel (see Section 1).

On a regional basis, product stocks rose 15% in the Atlantic, led by a 150% jump in heavy fuel levels and a 5% increase in diesel. Other regions recorded more moderate gains.

While absolute stocks were up 4%, in part reflecting strong consumption trends, the seasonal inventory build was much smaller in the first quarter of 1988 than in the year-earlier period, as end-1987 stocks were already above (15%) end of 1986 levels. However, due to higher consumption levels, the ratio of stocks to sales at the end of the quarter was the same as the beginning, that is 70 days.

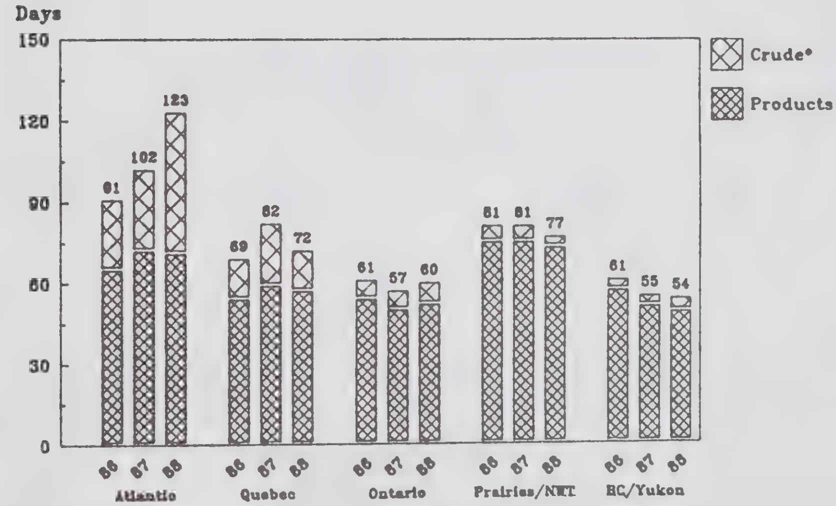
On a year-over-year basis, the ratio was 2 days (4%) higher due to a 7% (5% excluding Come-by-Chance) increase in inventory level and a 3% increase in sales. The extent to which refiners and marketers are able to increase their sales without a corresponding increase in inventories reflects greater efficiencies in their operations, and should yield a corresponding improvement in earnings. This behaviour was particularly evident in the Prairies where stocks rose by about 7% as compared to last year, but the ratio of stocks to sales fell by 3%.

CLOSING INVENTORIES – BY REGION
MARCH



Source: Statistics Canada

RATIO OF STOCKS TO CONSUMPTION



Source: Statistics Canada * excludes crude in pipeline tanks

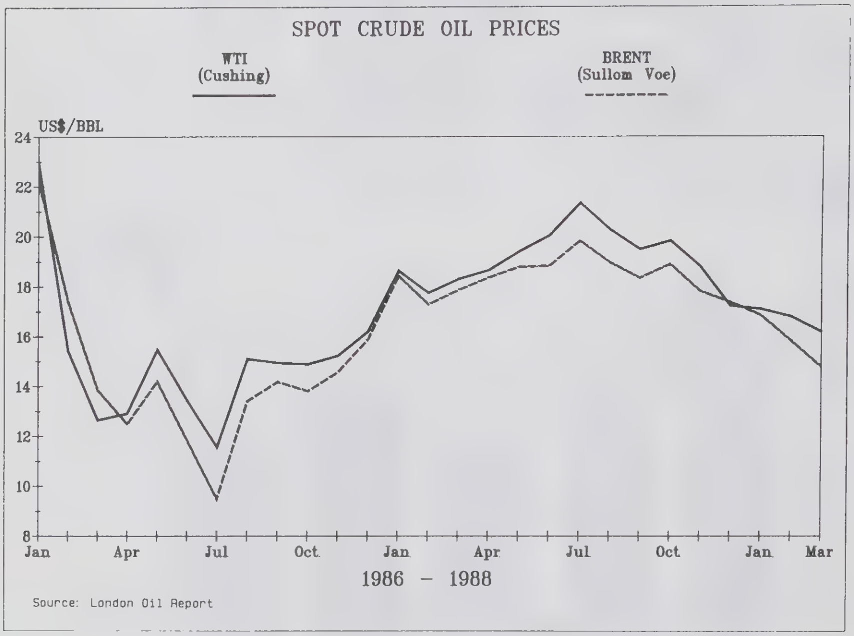
The stocks referred to above do not include crude oil in pipelines or related tankage. If these were added in, the ratio of stocks to consumption would rise by about 8 days, to 78. This compares with an OECD average for the end of the quarter, of 72 days, measured on a roughly comparable basis. (Including government stocks, the OECD average was 102 days.)

10. Prices

10.1 International Crude Oil Prices

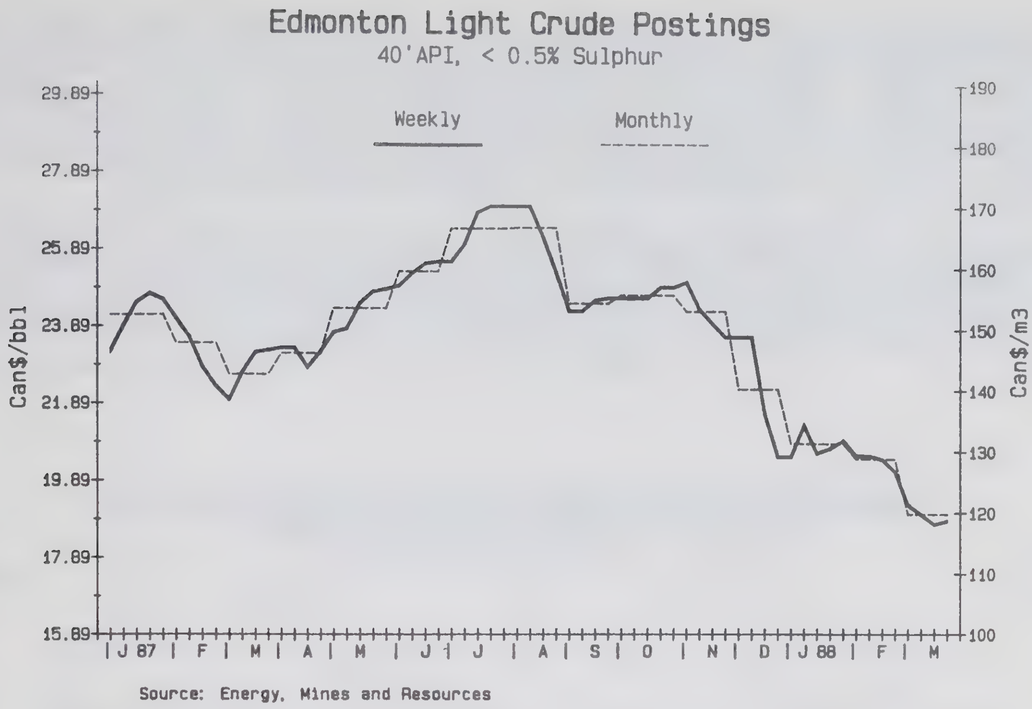
In January, spot crude oil prices firmed slightly from the relatively low level in December when West Texas Intermediate (WTI) fell to $15.15/bbl. OPEC appeared to be unofficially cutting back on output and attempting to pull supply and demand into closer balance. Unlike the first quarter of 1987, no OPEC producer was willing to play the role of swing producer which would have required production cuts significantly below quota. Instead, virtually all OPEC producers began to discount crude oil at market-related prices in order to maintain quota volumes. Price discounting on the part of OPEC, an abundance of crude and oil products held in inventories, and continued increases in non-OPEC volumes, kept spot crude oil prices $3 to $4/bbl below OPEC's $18/bbl benchmark.

Spot crude oil prices reached a low point in early March with WTI falling to almost $15/bbl and UK Brent below $14/bbl. By mid-March however, the market began to recover as various OPEC members campaigned to hold a price committee meeting with the potential of calling a full OPEC conference to cut production and regain control of the market. The graph below tracks the movement of spot prices of WTI and Brent over the period January, 1986 to March, 1988.

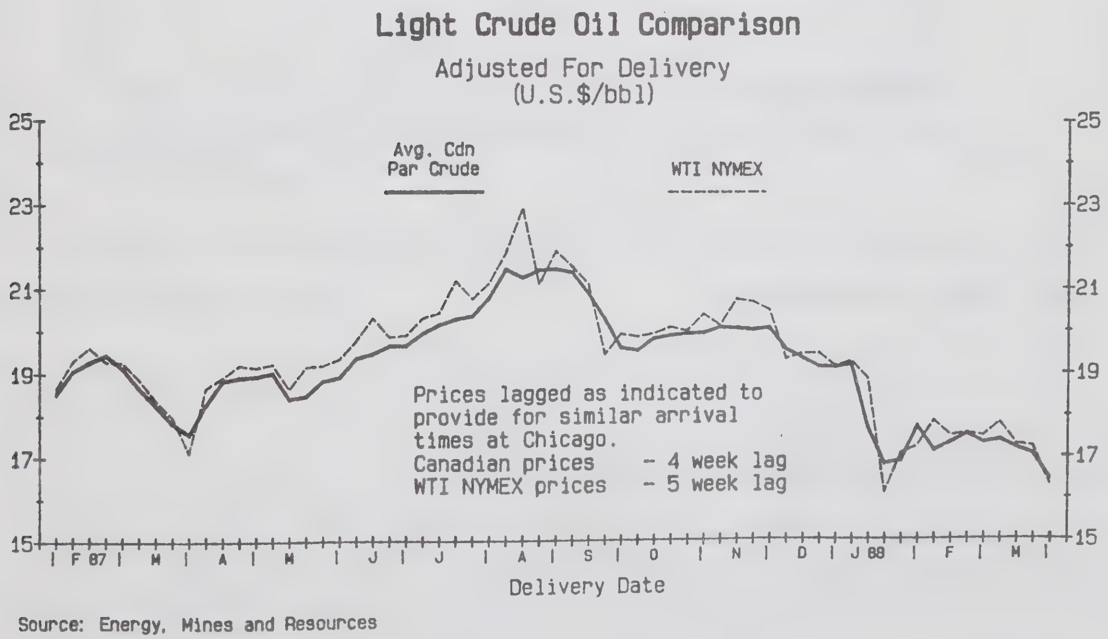


10.2 Domestic Crude Oil Prices

Canadian light crude oil prices during the first quarter of 1988 were about $20.10 per barrel, a decrease of $3.65 from fourth quarter of 1987 prices. The decline in crude oil prices was attributable to two main factors; the downward trend in world oil prices (see Section 10.1) and the strengthening of the Canadian dollar against the U.S. dollar. Between the fourth quarter and the first quarter of 1988, the exchange rate effect on Canadian crude prices was estimated at about $0.75 per barrel. (Based on first quarter of 1988 production levels, this would amount to a $115 million or a 4% reduction in well-head revenues, before royalties and taxes.)



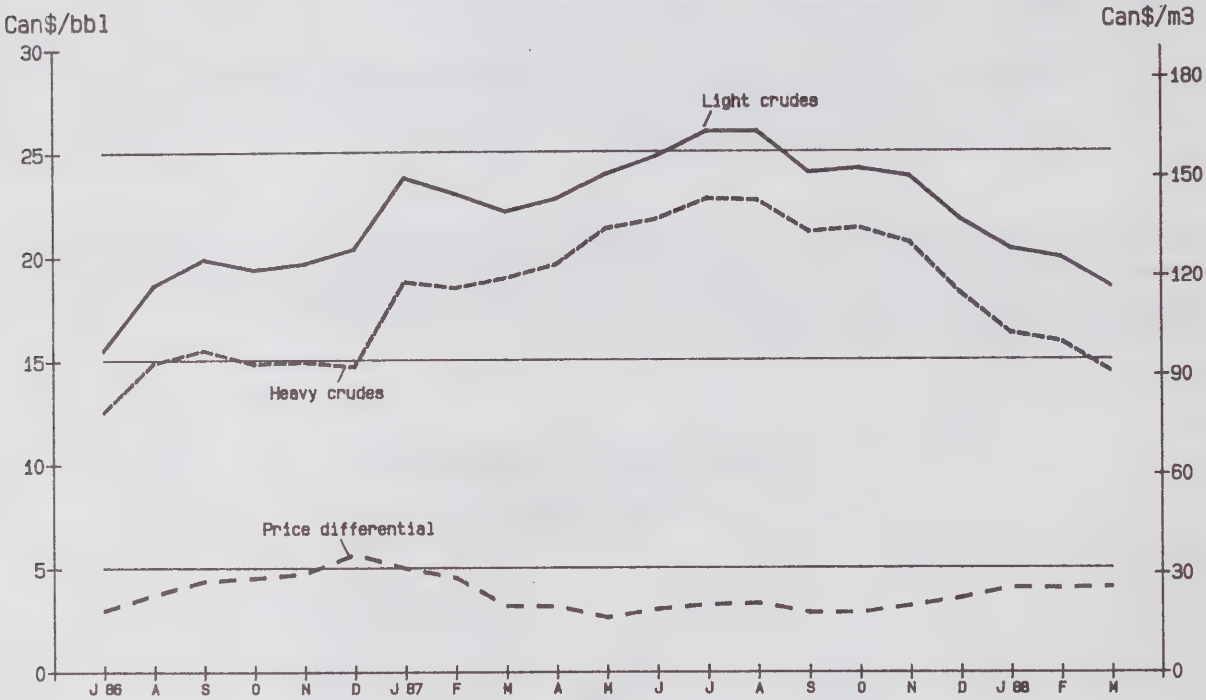
Canadian light crude oil prices follow the trend set by international crudes, primarily the U.S. benchmark WTI. The following graph illustrates the close relationship between prices for WTI and Canadian crudes, after adjustments for delivery times to Chicago.



The graph below compares actual prices for Alberta light and heavy crude oil, purchased for use in Canada at main trunk line injection stations. On average, light crude oil quality during the first quarter 1988 was 37.7° API, 0.41% sulphur and heavy crude was 24.3° API, 2.48% sulphur. The variation in the price differential shown at the bottom of the graph is largely explained by the influence of seasonal demand factors.

The differential between Canadian light and heavy crude prices during the first quarter was about $4.00 per barrel, similar to the level of one year ago. The weaker demand for heavy Canadian crudes in the winter months (seasonal asphalt market) is responsible for the spread.

Comparison of Domestic Light and Heavy Crudes
Actual Purchase Prices (Alberta)



Source: Energy, Mines and Resources

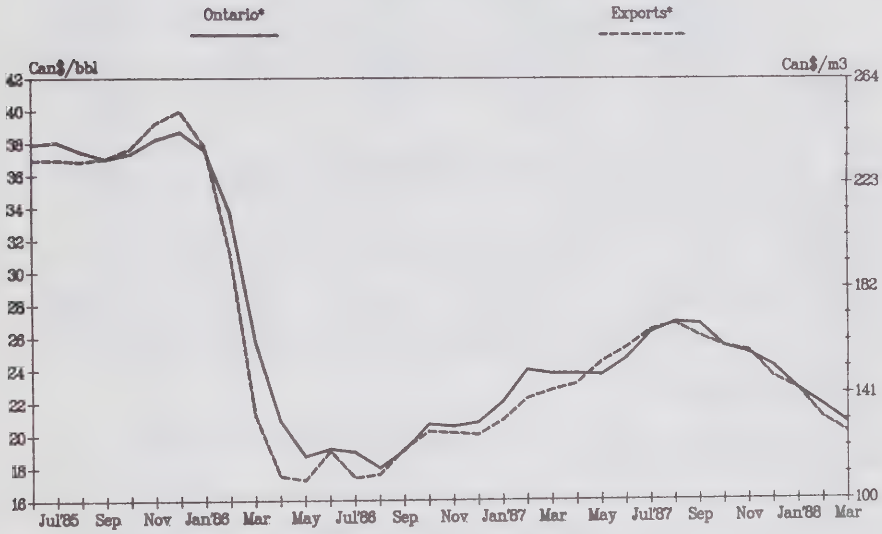
10.3 <u>Light Crude Values: Export versus Domestic</u>

Consistent with the trend established since mid-1987, the average value of light crude exports and domestic light crudes delivered to Ontario refiners in the first quarter (using Ontario as a proxy for average Canadian refiner acquisition costs of indigenous light crude & equivalent) were similar, with a slight advantage for exports.

At the beginning of the quarter, prices/values were virtually identical at $22.75/bbl. With falling international prices and continuing pipeline apportionment, export prices dropped faster than domestic values such that by March a $0.60 gap had developed. The average value of domestic light crude to Ontario was $20.65 versus $20.05 for exports.

The pipeline constraints in the first quarter contributed to some export discounting, as U.S. refiners attempted to offset the risk associated with deliveries that could potentially be reduced. Also the effect of falling prices are usually reflected sooner in the United States because of shorter supply lines compared with Ontario deliveries.

Canadian Light Crude Export & Ontario
Domestic Acquisition Values
(Adjusted to 38 API, 0.6% S.)



* Both values adjusted for transportation cost to a common point (Ontario)

Source: Energy, Mines and Resources

10.4 Petroleum Product Prices

Retail prices of regular unleaded gasoline fell an average of 3 cents per litre during the first quarter of 1988. Price declines were recorded in ten of the eleven centres surveyed. With the exception of Charlottetown, where the price increased marginally, prices fell between 0.3 and 2.9 cents per litre in eastern Canada. Price war activity in western Canada contributed to declines ranging from 2.1 to 9.1 cents per litre.

The average Canada regular unleaded price in March 1988 was 7.5 cents per litre or 13.4 per cent lower than the price in January 1986, the period prior to the flowthrough of the steep crude oil price decline of the first quarter of 1986.

AVERAGE REGULAR UNLEADED GASOLINE PRICES
FULL-SERVE AND SELF-SERVE
1987-1988

	1987 March	1987 June	1987 Sept.	1987 Dec.	1988 March	Change Last 12 months
	(cents per litre)					(%)
St. John's (Nfld.)	56.2	55.8	55.6	55.5	55.2	-1.8
Carlottetown	53.6	53.4	53.3	53.3	53.4	-0.4
Halifax	52.7	49.3	48.9	51.5	50.8	-3.6
Saint John (N.B.)	47.9	48.9	48.7	50.7	49.6	3.6
Montreal	57.0	56.9	57.8	57.9	56.9	-0.2
Ottawa	50.0	50.8	51.9	51.8	51.4	2.8
Toronto	45.9	47.6	50.6	49.4	46.5	1.3
Winnipeg	48.3	48.0	48.1	47.8	43.9	-9.1
Regina	42.8	42.1	46.6	50.3	48.2	12.6
Calgary	41.1	46.2	44.2	47.2	38.1	-7.3
Vancouver	48.4	50.3	52.8	51.2	48.5	0.2
Canadian average	48.6	49.9	51.4	51.4	48.4	-0.4
Consumption taxes included:						
Federal	9.35	9.05	8.79	8.79	8.86	-5.2
Provincial	8.48	9.39	9.43	9.45	9.41	11.0

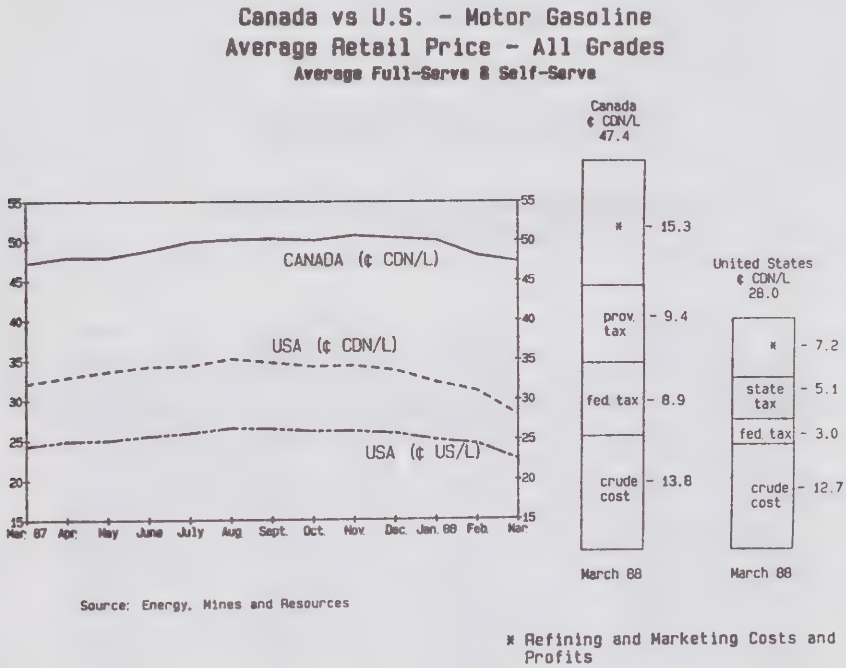
Source: Statistics Canada

Retail diesel prices continue to be stable with the average March of 1988 price only 0.1 cent per litre below the December of 1987 price. A diesel price war in Edmonton during the last two weeks of March is primarily responsible for the slight decline.

Changes to federal or provincial gasoline and diesel consumption taxes were moderate during the first quarter of 1988 (see Appendix II). Three of the provinces, all with ad valorem tax rates, made minor adjustments to their taxes. The federal sales tax was increased 0.07 cent per litre on regular leaded and regular unleaded gasolines, and 0.06 cent per litre on premium unleaded gasoline, while on diesel fuel it increased only 0.01 cent per litre. Combined federal taxes on regular unleaded in March of 1988 accounted for 18.3% of the pump price, as compared with 17.1% in December of 1987. The federal sales tax on gasoline is based on a 12% ad valorem rate and is adjusted quarterly to reflect changes in a twelve-month average industrial product price index for gasoline, with a one-quarter lag. Recent gasoline price declines will likely not affect the federal sales tax until July of 1988.

The following line graph and bar charts compare average gasoline prices in Canada and the United States.

The bar charts illustrates the components of the average pump price in each country using March of 1988 data. Crude costs are the average refinery acquisition costs (cost of crude received at the refinery gate) lagged by 60 days in Canada and 45 days in the United States. The refining and marketing costs and profits component is the residual revenue available to cover refining, marketing and distribution costs and to provide a return to the industry on its investment.



The average pump prices in Canada and the United States fell 3.0 and 5.7 cents per litre, respectively, during the first quarter of 1988. Almost one-quarter of the reduction in the average U.S. price, quoted in Canadian funds, was attributable to a strengthening Canadian dollar.

Gasoline prices in Canada in March of 1988 were 19.4 cents per litre higher than in the United States. This reflects a widening in the differential during the last quarter of 2.7 cents per litre, of which half can be attributable to the above-mentioned strengthening of the U.S. dollar. Over one-half of the differential in March was accounted for by higher taxes in Canada (10.2 cents per litre). Most of the balance is attributable to higher refining and marketing costs and profits in Canada. The larger refining and marketing costs and profits component in Canada results from structural differences between the two markets e.g. economies of scale in refining, distribution and retailing facilities favour U.S. refiners and marketers.

In March of 1988, residential furnace oil prices in the Atlantic provinces were about the same as in March of 1987. In Nova Scotia, two Public Utility Board decisions resulted in a furnace fuel price rollback in April of 1987, and approval of a price increase in October of 1987. In Quebec, prices fluctuated slightly during the 1987 and 1988 heating season, while in Ontario increases took place at the end of the 1986 and 1987 heating season and in December of 1987. Overall, price changes ranged from a decline of 0.3 to an increase of 2.6 cents per litre (-1.0% to +8.6%) during the 1987 and 1988 heating season.

Residential Furnace Oil Prices
1987-1988

	Mar. 1987	Sept. 1987	Dec. 1987	Mar. 1988	Change last 12 months
	(Canadian cents per litre)				%
St. John's (Nfld.)	32.4	32.4	32.4	32.4	0.0
Charlottetown	32.3	32.3	32.3	32.3	0.0
Halifax	29.9	27.4	29.6	29.6	-1.0
Saint John (N.B.)	33.0	33.0	33.0	33.0	0.0
Quebec City*	29.8	29.1	31.5	30.7	3.0
Montreal*	28.6	29.5	30.0	30.0	4.9
Ottawa	31.2	31.5	32.9	32.8	5.1
Toronto	30.3	31.4	32.4	32.9	8.6

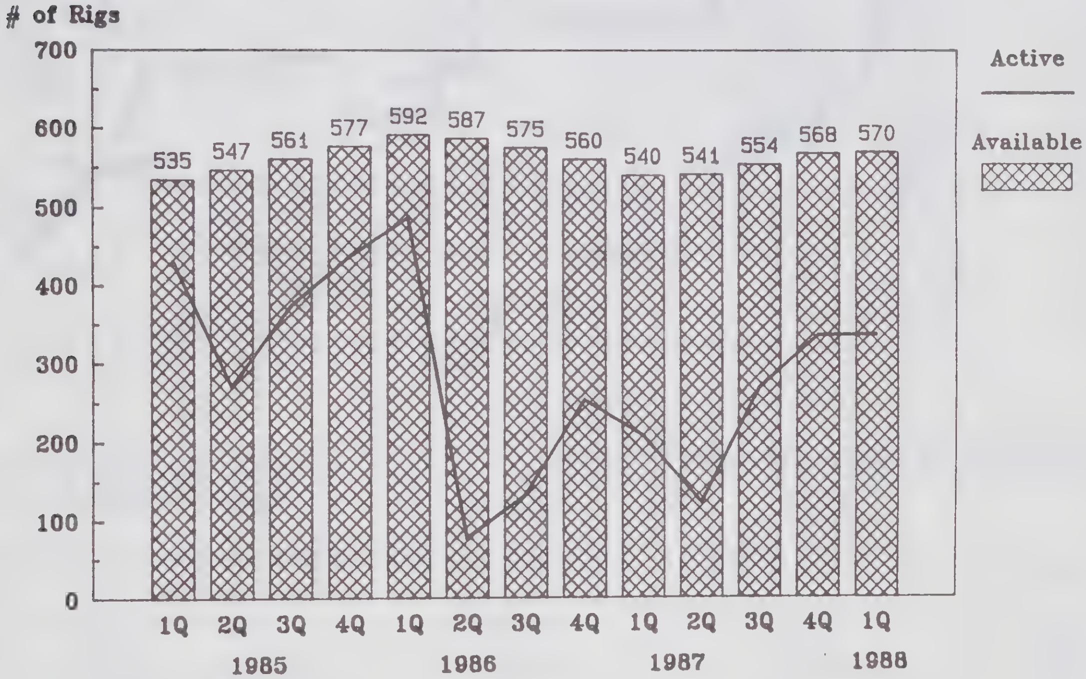
* includes 9% provincial sales tax

Source: Statistics Canada

11. Drilling Rig Activity

Although the first quarter is generally the strongest one for drilling rig activity, rig utilization for the beginning of 1988 averaged only 59% with 336 out of 570 rigs working. Following a drop that started in late 1987, in part due to the elimination of certain grants and royalty hodidays, activity rebounded in February to its highest level since the first quarter of 1986. The industry was then faced with an earlier-than-usual spring thaw, which, with the resulting road bans, led to a decline in active rigs to less than 300. Nonetheless, the utilization rate was 21 percentage points higher than in the first quarter of 1987 and included a larger number of rigs available for work, which indicated increased oil industry confidence.

CANADIAN RIG ACTIVITY



Source: Energy, Mines and Resources

APPENDIX I

LIGHT AND HEAVY CRUDE EXPORTS BY DESTINATION

Petroleum Administration for Defense (PAD) Districts

Destinations	Light				Heavy		
	1986	1987	1988*	000 m³/d	1986	1987	1988*
U.S.							
PADD 1	6.8	6.5	7.4		1.5	2.5	0.9
PADD 2	18.7	16.8	28.6		43.9	46.2	52.0
PADD 3	0	0	0		0	1.4	3.5
PADD 4	3.3	8.1	5.9		3.4	3.2	4.7
PADD 5	3.6	3.6	1.5		0	0.4	0.3
Total U.S.	32.4	35.0	43.4		48.8	53.7	61.4
Offshore	0	0	0.7		0.7	0.5	4.4
Total Exports	32.4	35.0	44.1		49.5	54.2	65.8

* March 1988 estimated

Source: National Energy Board

APPENDIX II

CONSUMPTION TAXES ON PETROLEUM PRODUCTS
March 1, 1988

	Ad valorem		Gasoline			
	Mogas	Diesel	Reg L	Reg UL	Prem UL.	Diesel
	%		(cents per litre)			
Federal Taxes						
Sales			3.36*	3.36*	3.44*	2.63*
Excise			5.5	5.5	5.5	4.0
Provincial Taxes						
Newfoundland	22	26	9.8	9.8	9.8	12.1
Prince Edward Island	20	23	8.9	8.9	8.9	10.4
Nova Scotia	20	21	8.7	8.7	8.7	9.0*
New Brunswick	20	23	7.8*	8.4*	8.7*	8.0*
Quebec (a)	-	-	14.4	14.4	14.4	12.45
Ontario	-	-	8.3	8.3	8.3	9.9
Manitoba	-	-	8.9	8.0	8.0	9.9
Saskatchewan	-	-	7.0	7.0	7.0	7.0
Alberta	-	-	5.0	5.0	5.0	5.0
British Columbia	20(b)	20(b)	9.89*	7.89*	7.89*	8.33*
Yukon	-	-	4.2	4.2	4.2	5.2
Northwest Territories	17	(c)	8.7	8.7	8.7	7.4

(a) Reduced by varying amounts in certain remote areas and within 20 kilometres of the provincial and U.S. borders.

(b) Additional transit tax of 2.5 cents per litre in Vancouver.

(c) 85% of gasoline tax.

* Changed since last quarter.

Source: Statistics Canada

Glossary

Bitumen	A naturally occurring viscous mixture composed mainly of hydrocarbons heavier than pentane, which may contain sulphur compounds and which in its natural state is not recoverable at a commercial rate through a well.
Conventional areas	Those areas of Canada that have a long history of hydrocarbon production. Conventional areas are also referred to as nonfrontier areas.
Crude oil and equivalent	Includes crude oil, synthetic crude oil produced from oil sands plants, and condensate.
Feedstock	Raw material supplied to a refinery or petrochemical plant.
Heavy crude oil	Loosely applied, crude oils with a low API gravity (high density).
In situ recovery	With reference to oil sands deposits, the use of techniques to recover bitumen without the necessity of mining the sands.
Light crude oil	Crude oil with a high API gravity (low density). Generally includes all crude oil and equivalent hydrocarbons not included under heavy crude oil.
Natural gas liquids	Thos hydrocarbon components recovered from raw natural gas as liquids by processing through extraction plants, or recovered from field separations, scrubbers or other gathering facilities. Includes the hydrocarbon components ethane, propane, butane and pentanes plus, or a combination thereof.
Oil sands	Deposits of sands and other rock aggregate that contain bitumen.
Pentanes plus	Also referred to as condensate. A volatile hydrocarbon liquid composed primarily of pentanes and heavier hydrocarbons. Generally a by-product obtained from the production and processing of natural gas.

Glossary (continued)

Productive capacity	The estimated production level that could be achieved, unrestricted by demand, but restricted by reservoir performance, well density and well capacity, oil sands mining capacity, field processing and pipeline capacity.
Shut-in capacity	The unused production capability of currently producing oil and gas wells plus the total production capability of all shut-in oil and gas wells, whether or not they are connected to surface gathering and production facilities.
Synthetic crude oil	Crude oil produced through treatment of oil sands in upgrading facilities designed to reduce the viscosity and sulphur content.

Energy, Mines and Resources Canada
Énergie, Mines et Ressources Canada

The Canadian Oil Market

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Canada

THE CANADIAN OIL MARKET

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Index

List of Figures

The Canadian Oil Market

Overview

Both the production and the demand for crude oil and equivalent were higher in the second quarter of 1988, compared with the second quarter of 1987. As a result of additional pipeline capacity and strong demand, production increased more than 5%, to 270 000 m^3/d. Output of both light and heavy crude increased.

Approximately three quarters of the incremental production was exported. Exports were up 11%, to 118 000 m^3/d on a year-over-year basis, accounting for 43% of crude oil production. Close to 10% of exports were by tanker, as producers expanded and diversified markets in the Pacific Rim and U.S. destinations in PAD Districts I and III.

Canadian refiners increased their receipts of domestic crude by 2%, reflecting a slight increase in consumption and an improvement in the product trade balance. Refined product sales were up less than 0.5%, which was down sharply from a robust growth in the first quarter. However refinery utilization was higher, increasing 4% percentage points to 78%, primarily because of a jump in net product exports, which more than tripled, to 23 000 m^3/d. Product exports now account for 10% of refinery crude throughput.

Largely as a result of an increase in product exports under crude oil import and product export agreements, crude oil imports were up 30% to 67 000 m^3/d.

Crude oil prices rose slightly in the second quarter, compared with the first quarter. Although international prices rose $US 0.75 per barrel, a strengthening in the Canadian dollar offset more than two thirds of the increase.

With respect to transportation facilities, the main pipeline distribution system operated at capacity throughout the second quarter, as it did in the first, because of strong demand and higher crude oil supply. There was marginal crude oil shut-in capacity.

In May 1988, reflecting a trend to more optimistic crude oil supply forecasts, the two major oil pipeline companies in Canada, Interprovincial Pipe Line Company (IPL) and Trans Mountain Pipe Line (TMPL), both announced tentative plans for major expansions, at estimated costs of $1.1 billion and $500 million, respectively. An industry consensus has not yet developed with respect to the need for these expansions, either now, or in the next five or six years.

According to a mid-year review of capital expenditure intentions, in 1988 petroleum related (including natural gas) capital expenditures are forecast to exceed $9.2 billion, a 29% increase over 1987. Much of the increased expenditure is expected to occur in the upstream industry, reflecting increased exploration and project expenditures in both the oil and natural gas sectors.

The Canadian Oil Market

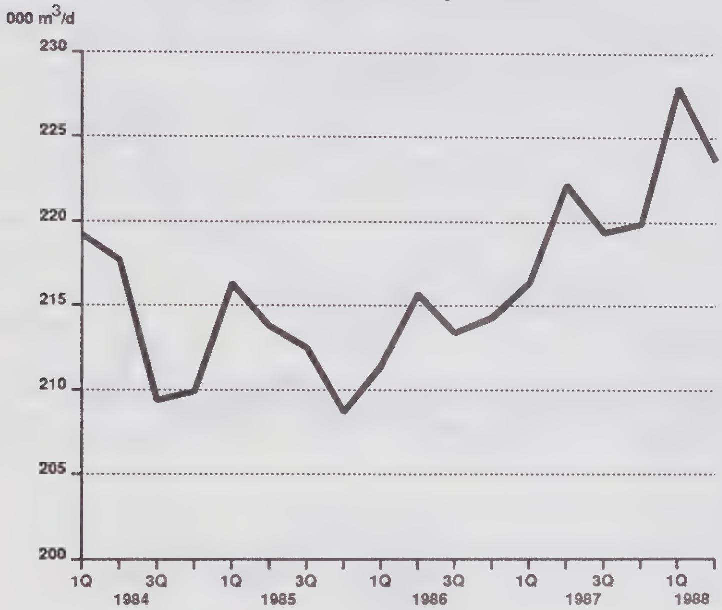
1. Domestic Demand

1.1 Seasonally Adjusted

Seasonally adjusted petroleum product consumption in Canada during the second quarter of 1988 decreased to 224 000 m^3/d, down 1% from the previous quarter, but almost 2% higher than the average for 1987.

Figure 1.1.1

Total Petroleum Product Consumption
(Seasonally Adjusted)



Source: Statistics Canada

This slight decline in consumption was largely the result of a decrease in transportation fuel use. In this sector, demand was almost 4% lower at 135 000 m^3/d, with motor gasoline sales decreasing 6%, to 90 000 m^3/d and diesel down 3%, to 45 000 m^3/d. In the case of motor gasoline, sale levels returned to the quarterly averages recorded in 1987 and negated the large increase recorded in the first quarter of 1988. The sales of diesel, although lower than in the first quarter, remained high compared with 1987 figures.

Heating oil sales at 22 000 m^3/d, were up 5% from the first quarter with increases in Ontario averaging 42% over 1987. Temperatures in eastern Canada, including Ontario, were colder than normal in 1988 versus 1987.

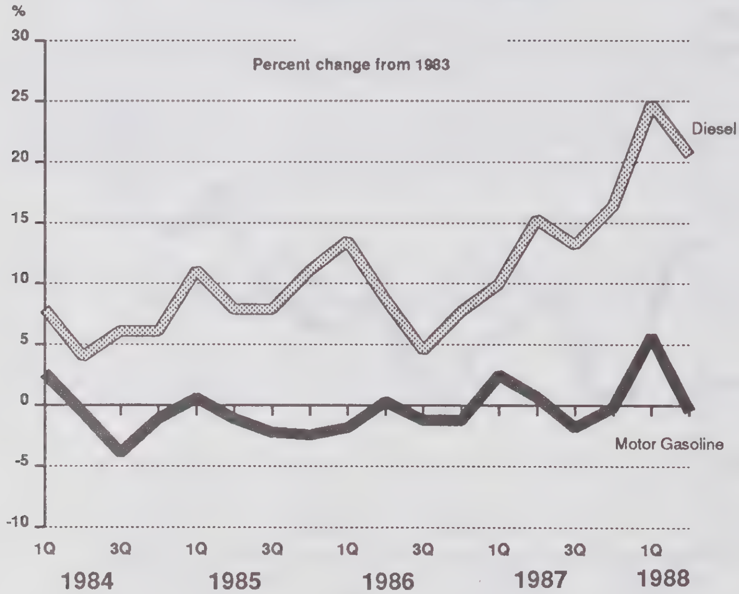
Heavy fuel oil remained steady with sales of 20 000 m^3/d, close to the highest level since 1983. The increased use of this product for thermal electricity generation in the Atlantic region, and by pulp and paper companies in Quebec, were major factors in the higher consumption over the last year. Sales of 'other products', comprising 20% of total trade in petroleum products, jumped 10% (4 000 m^3/d) to 46 000 m^3/d.

Figure 1.1.2 demonstrates the quarterly trend in consumption of transportation fuels using 1983 seasonally adjusted sales as a base. Motor gasoline sales fluctuated within a narrow range throughout this period and in the second quarter of 1988 remained virtually unchanged from the average 1983 level. Increased fuel efficiencies and relatively high gasoline prices were factors which contributed to lower consumption in 1984 and 1985. Subsequently, stronger economic growth which led to higher car sales, combined with lower gasoline prices which encouraged greater travel (although governments captured part of the decline in crude oil prices) more than offset the higher fuel efficiency of newer car fleets.

In the case of diesel fuel, 1988 consumption was more than 20% above 1983 demand, primarily because of economic growth, particularly in the industrial and commercial sector over the last two years. There was also some switching from motor gasoline to diesel fuel.

Figure 1.1.2

Trends in Motor Gasoline and Diesel Fuel Consumption



Source: Statistics Canada

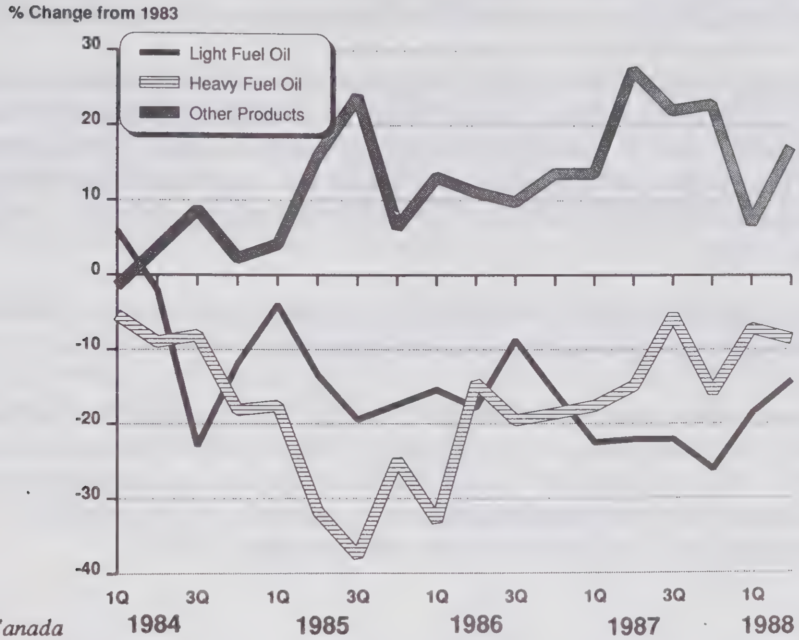
Figure 1.1.3 outlines the quarterly variation for heavy fuel, heating oil and 'other products'. During 1984 and 1985, heavy fuel oil consumption fell, reflecting conservation and substitution which were supported by various government incentives and programs and relatively high prices for heavy fuel oil. In 1986, with the drop in oil prices, heavy fuel oil once again was competitive with alternatives, particularly for customers with dual-fired systems. In the Atlantic region, the use of heavy fuel oil increased substantially in electricity generation as a result of poor hydrogeneration conditions and competitive prices.

Heating oil demand has declined with the expansion of natural gas and electricity markets, notably in Quebec, and warmer winters. The small increase in 1988 can partly be attributed to a colder winter in eastern Canada (including Ontario).

'Other product' sales, (which include petrochemical feedstocks and jet fuels) pushed by a strong economy steadily improved through the second quarter of 1987. The decline since that period was mainly due to lower petrochemical feedstock sales.

Figure 1.1.3

Trend in Non-Transporation Fuel Consumption



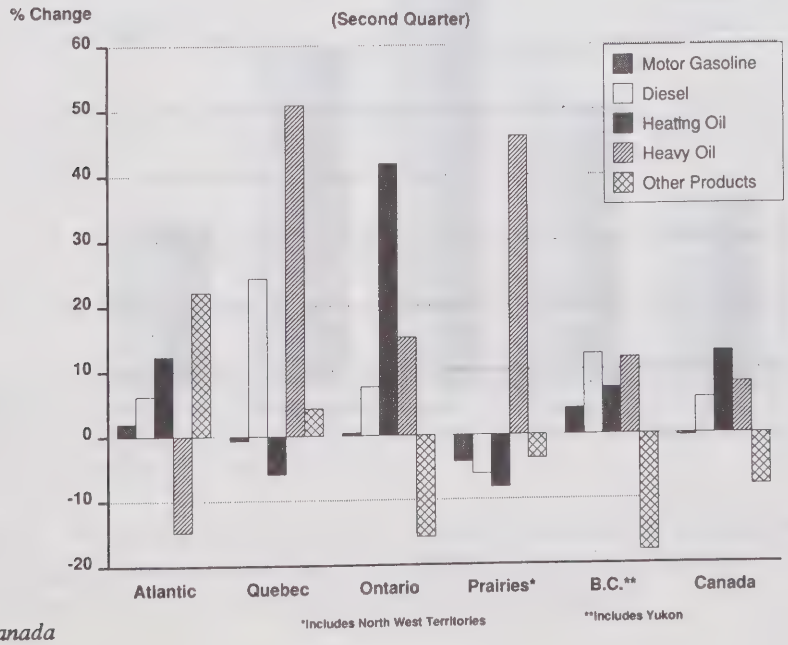
Source: Statistics Canada

1.2 Regional Consumption

Compared with the second quarter of 1987, nationwide demand (unadjusted) was up less than 0.5% in the second quarter of 1988.

Figure 1.2.1

Canadian Oil Product Consumption
1988 vs 1987



Source: Statistics Canada

The largest increase in regional demand occurred in Quebec where domestic sales were 8% higher than in the second quarter of 1987. Total sales of almost 44 000 m^3/d included a 51% (1 700 m^3/d) increase in heavy fuel oil use, to 5 000 m^3/d, which reflected additional activity in the pulp and paper industry. Diesel fuel sales were also up, by 24%, to 8 000 m^3/d in line with stronger economic activity.

In Ontario, where over one third (73 000 m^3/d) of all domestic petroleum products are consumed, sales were 1% lower than a year before. 'Other product' sales, at 19 000 m^3/d, were 16% less than in 1987 with most of the decrease due to lower petrochemical feedstock sales. This drop reflects some substitution of liquid petroleum gases for natural gas liquids and a turnaround at a petrochemical plant. An 8% (1 000 m^3/d) increase in demand for diesel fuel and the sharp jump in heating oil sales offset some of the decline in other products.

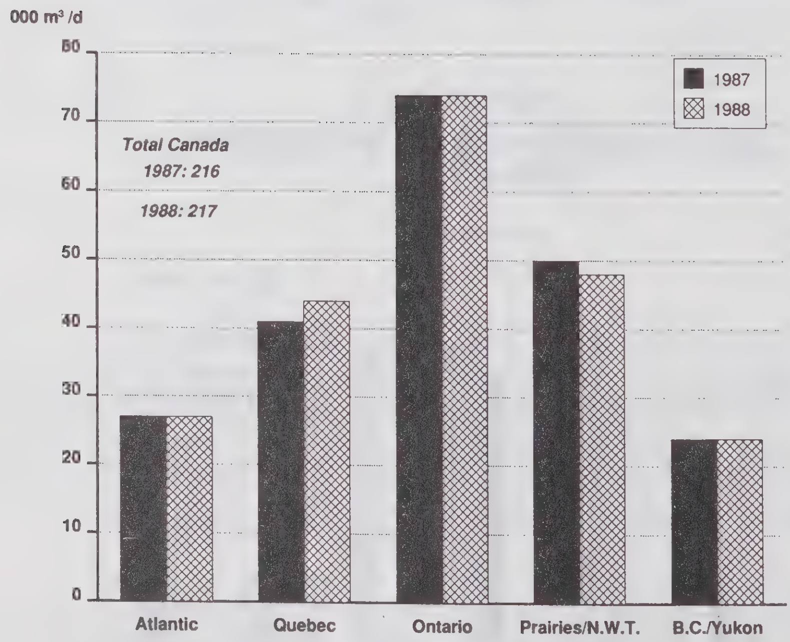
In the Prairies, consumption dropped 4% to 48 000 m^3/d. The lower sales were recorded in all categories as the effect of the drought began to be felt in petroleum product use.

In British Columbia where total consumption was 24 000 m^3/d, up more than 2%, increases were posted in all categories, except for 'other products' which dropped 18% to 4 000 m^3/d. Gasoline sales, on a slide during the latter part of 1986 and all of 1987, may have turned around as demand was up 4% to 10 000 m^3/d. This was the largest year-over-year improvement in any region and possibly was the result of increased tourist traffic enjoyed by the province during the first half of 1988.

Figure 1.2.2

Regional Petroleum Product Consumption

(Second Quarter)



Source: Statistics Canada

1.3 Sales of Gasoline By Grade

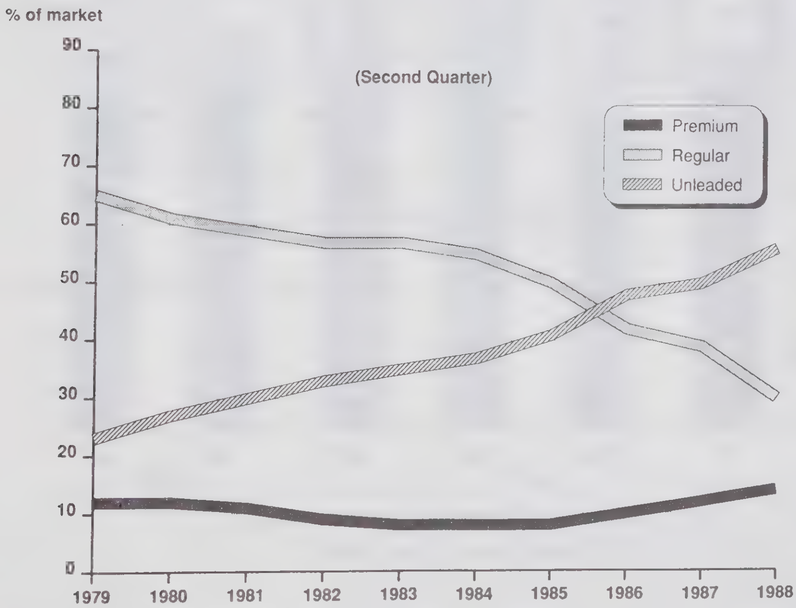
On an unadjusted basis, total motor gasoline sales during the second quarter of 1988 averaged 93 000 m^3/d, just slightly less than in the same period in 1987.

Motor gasoline accounted for about 43% of total petroleum product consumption in Canada, unchanged from a year ago. Leaded gasoline sales of 28 000 m^3/d were 22% below 1987 levels and accounted for 30% of the market, 8 percentage points lower than a year earlier. Most of the volume has been absorbed by the regular unleaded market, up 13% to 52 000 m^3/d (a 56% market share). Premium unleaded, with 14% of total sales, accounted for the remaining 13 000 m^3/d, 2 000 m^3/d higher than last year. Figure 1.3.1 illustrates the changing mix of gasoline sales since 1979.

- Effective April 20, 1988, the Ontario government increased the provincial tax on leaded gasoline so that it currently exceeds the tax on unleaded gasolines. This move is to encourage the use of the unleaded gasoline by eliminating the cost advantage of unleaded fuel. New Brunswick is now the only province where the provincial tax is less on leaded fuel than on unleaded.

Figure 1.3.1

Motor Gasoline Sales
Market Share by Grade



Source: Statistics Canada

1.4 International Energy Consumption

Preliminary data from the Organization for Economic and Cooperative Development (OECD) showed that, on average, growth in energy consumption for member countries was 2% higher in the second quarter of 1988 versus a year earlier. In Europe consumption was higher by over 3%. In most areas, transportation fuels led the second-quarter growth.

In the United States the rate of growth in demand slowed, increasing by less than 1% over 1987, whereas in the Pacific region, consumption was 2% higher than a year earlier. In these two regions, second-quarter growth was substantially lower than in the first quarter.

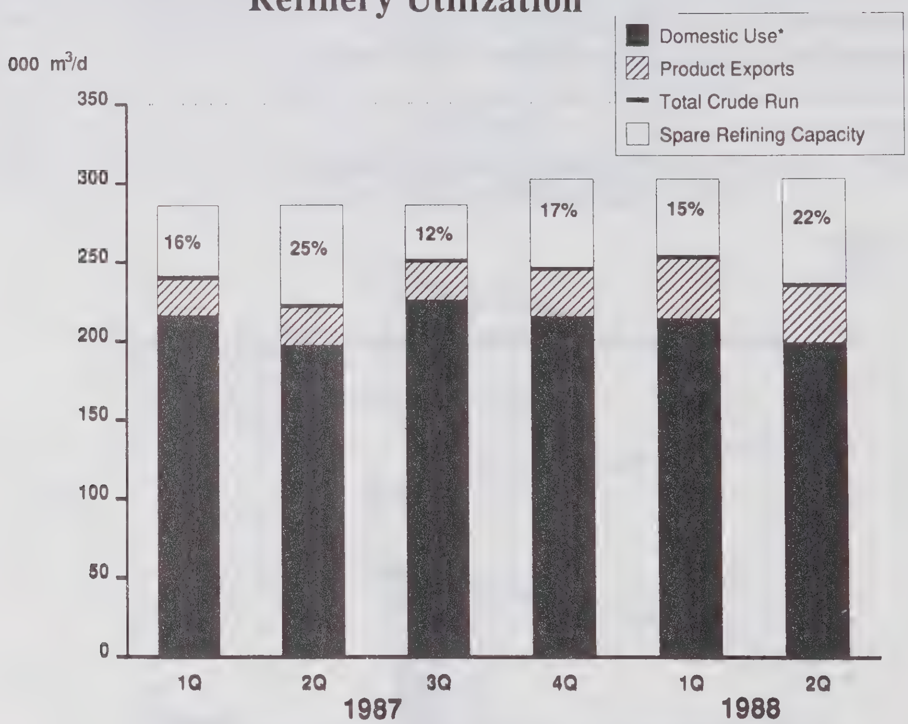
In contrast to 1987 and the first quarter of 1988, product sales growth in Canada, at less than 0.5%, was below the average of most industrialized countries.

2. Refinery Requirements

Crude run to stills during the second quarter of 1988 averaged 234 000 m^3/d, up 9% or 20 000 m^3/d which represented a national refinery utilization rate of 78%, up from 75% last year. Excluding the reactivated Come-by-Chance refinery in Newfoundland, throughput rose by about 4%, in order to satisfy higher petroleum product consumption and petroleum product trade opportunities. Utilization rates in both Quebec and the Atlantic were up 12 and 14 percentage points, to 84% and 77%, respectively, while throughput declined by 6 points in the Prairies, to 73%.

Figure 2.1.1

Refinery Utilization



***Adjusted for refinery gain**

Source: Statistics Canada and refiners' submissions to the National Energy Board

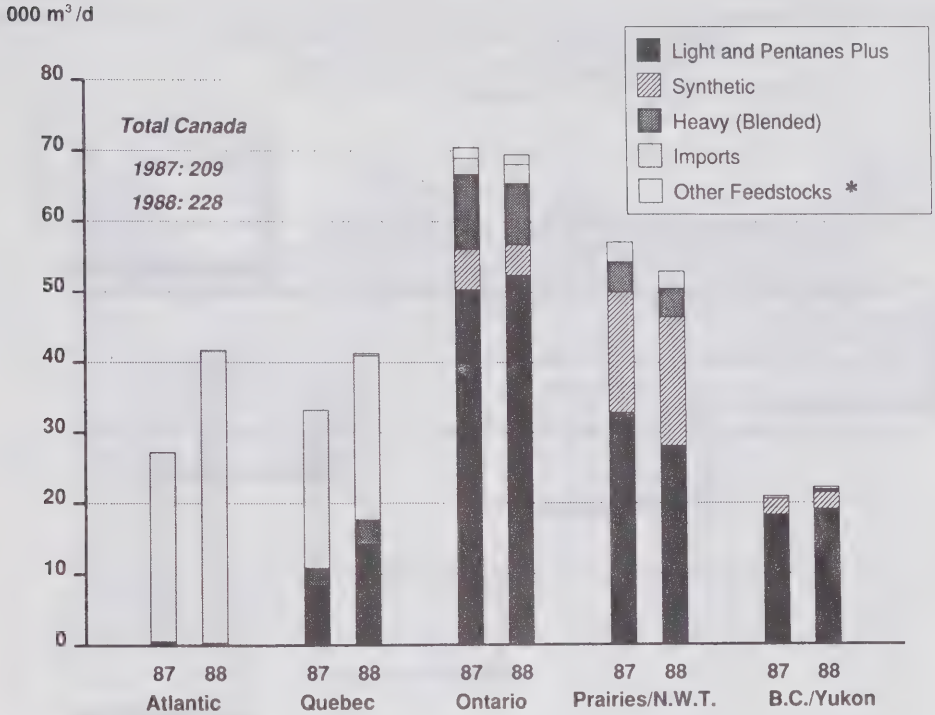
Refinery demand for Canadian crude oil averaged 161 000 m^3/d, an increase of 3 000 m^3/d or 2% from a year ago. Conventional light crude oil accounted for the bulk of deliveries, up 4% to 110 000 m^3/d, mainly reflecting higher demand in Quebec, while synthetic and pentanes plus remained unchanged at 25 000 m^3/d and 4 000 m^3/d respectively. Heavy crude oil deliveries, however, fell by 6% to 17 000 m^3/d. Gross crude oil imports were at 67 000 m^3/d up 31% and represented 28% of total refiners requirements compared with 24% last year.

Once again the Atlantic recorded the largest regional increase in crude throughput, up almost 64% to 45 000 m^3/d. About two-thirds of the increase was related to the reactivation of the Come-by-Chance refinery. Since petroleum product consumption remained virtually unchanged from a year ago, the remainder of the increase was also related to increased petroleum product exports from the refineries in New Brunswick and Nova Scotia. The importance of the refined product exports to the downstream oil market in the Atlantic has increased with the reactivation of the Come-by-Chance refinery. Product exports, mainly to the United States accounted for 50% of the crude throughput in the second quarter (versus a national average of 10%), compared with 20% last year.

Figure 2.1.2

Crude Oil and Equivalent Receipts by Regions

(Second Quarter)



** excludes partially processed oils*

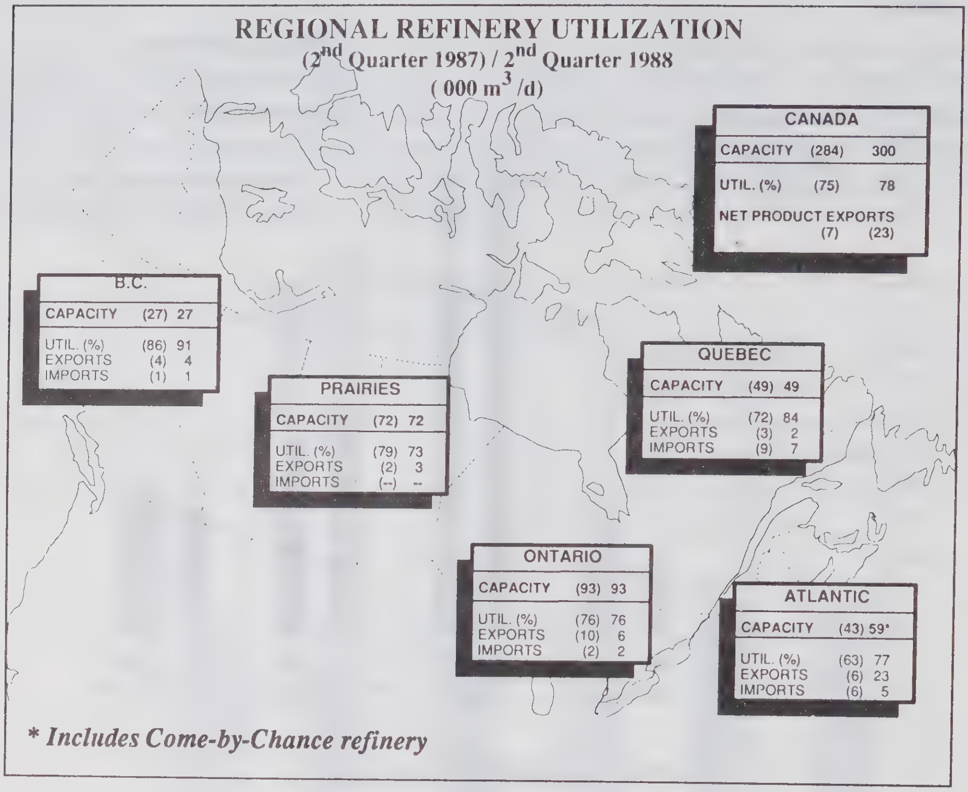
Source: Refiners' submissions to the National Energy Board

As a result of an 8% increase in petroleum product consumption, Quebec refinery runs recorded the second largest increase, to 41 000 m^3/d. Most of the increment was met by an increase in conventional light crude oil deliveries, up from 8 000 m^3/d to 14 000 m^3/d, while the other major feedstock components such as imports, synthetic and heavy crude only varied marginally from a year ago. It is interesting to note that Canadian crude oil deliveries accounted for 43% of total crude oil receipts, up 10 percentage points from a year ago.

Ontario throughput fell slightly to 70 000 m^3/d, in part, reflecting a drop of 1% in petroleum product consumption and a drop of 4 000 m^3/d in petroleum product exports.

The Prairies recorded the largest decline, down 8% to 53 000 m^3/d reflecting the shutdown of one major refinery during the month of June and a drop of 4% in petroleum product consumption. All of the decline occurred in conventional light crude oil.

Figure 2.1.3



Source: Refiners' submissions to the National Energy Board

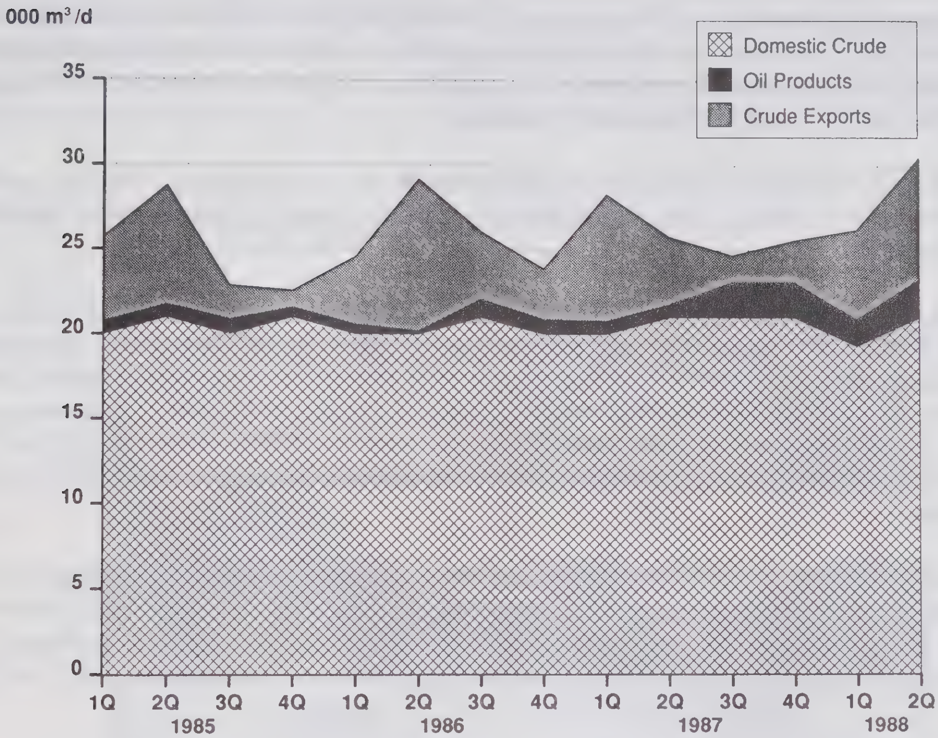
3. Pipelines

3.1 Trans Mountain Pipe Line Throughput

Trans Mountain Pipe Line throughput during the second quarter of 1988 averaged 31 000 m^3/d, an increase of 20% from both last year and the previous quarter. This throughput represented a 100% capacity utilization rate. (In fact, a 12% apportionment of excess demand for pipeline space by shippers was necessary in June.)

Figure 3.1.1

Trans Mountain Pipeline Deliveries



Source: Trans Mountain Pipe Line

Almost two thirds of the year-over-year increase (50/50 light/heavy) was related to a sharp increase in exports by tanker, which were up from 3 000 m^3/d to 5 000 m^3/d. This increase reflects producers efforts to penetrate the Pacific Rim region and the U.S. Gulf Coast market in the face of limited Interprovincial Pipe Line (IPL) capacity and a desire to broaden markets. The Pacific market offers potential because of its relatively greater use of heavy crude oil. Exports to Washington state remained virtually unchanged, at about 2 000 m^3/d.

Petroleum product movements more than doubled, from less than 1 000 m^3/d to over 2 000 m^3/d. In addition to an increase in petroleum product transfers, crude oil deliveries to domestic refiners rose by 4% to 22 000 m^3/d (including 4 000 m^3/d of partially processed oil) from a year ago.

3.2 Interprovincial Pipe Line Throughput

Total IPL deliveries of crude oil and other liquid hydrocarbons, including petroleum products and natural gas liquids during the first half of 1988 averaged 243 000 m^3/d, compared with 222 000 m^3/d over the same period in 1987. This increase reflected higher pipeline capacity and increased crude oil availability, particularly for heavy crude oil. Petroleum products and natural gas liquids accounted for approximately 5% of deliveries with crude oil making up the balance.

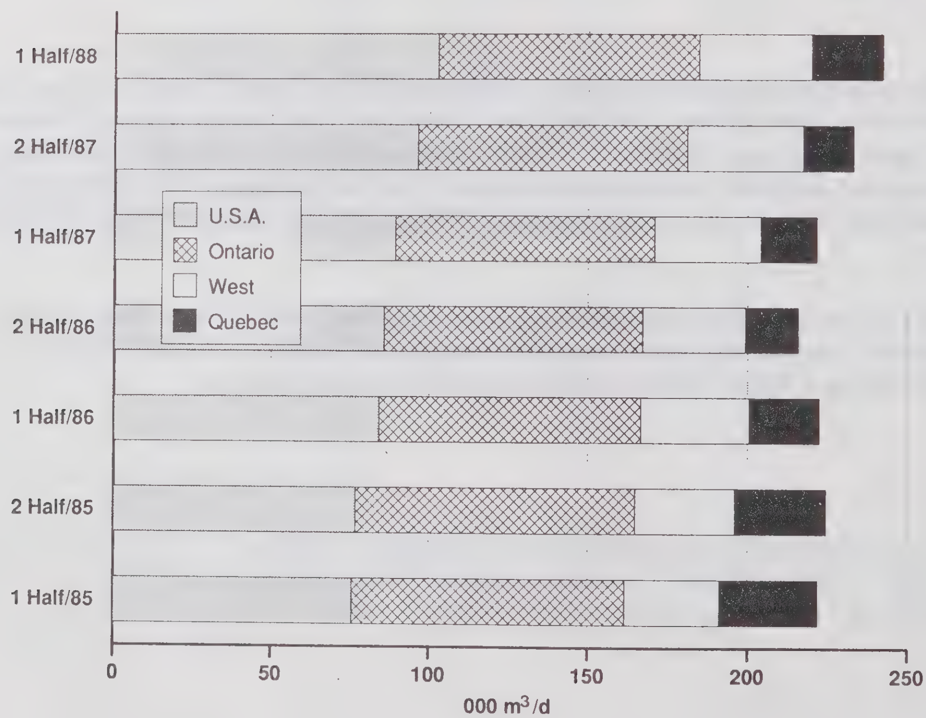
All regions recorded increases, ranging from 1% in Ontario to 27% in Quebec. The IPL system was full during the first half of 1988, in fact nominations for pipeline space by shippers were apportioned each month. (see figure 4.2.1).

Despite a drop of 4% in petroleum product consumption, crude oil deliveries to Western Canada rose by 7% to almost 36 000 m^3/d from a year ago, reflecting an inventory build. Strong U.S. demand and higher export availability contributed to a 15% increase, to 103 000 m^3/d, in deliveries to the United States (mainly to the Chicago area). Ontario deliveries increased slightly to 82 000 m^3/d, however, the crude mix shifted. Eastern Canada (Sarnia-Montreal) deliveries rose by 27% to almost 27 000 m^3/d reflecting an 8% growth in petroleum product consumption and an increase in exports and domestic transshipment out of Montreal.

In 1985, crude oil exports to the United States accounted for 39% of total IPL deliveries while in 1988 they represented 45%. This increase reflected crude oil price deregulation (June 1985) which shifted the flow of crude oil movement north/south rather than west/east and pipeline expansions (Phase I, II, and III) which provided additional capacity to the system, and continued additions to crude oil productive capacity.

Figure 3.2.1

Total IPL Deliveries



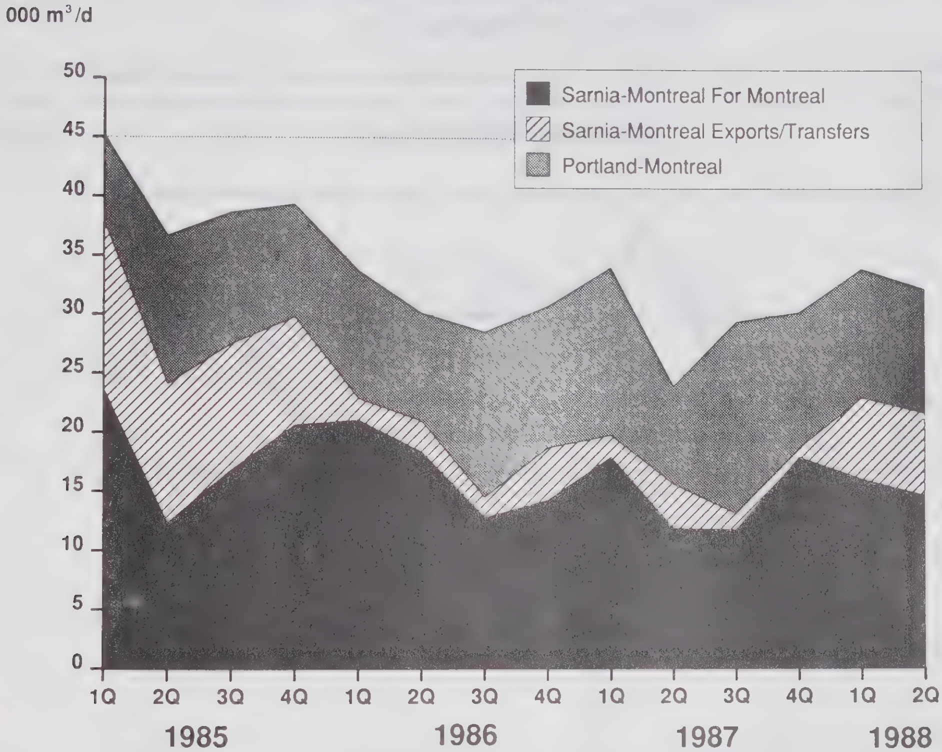
Source: Interprovincial Pipe Line

3.3 Pipelines to Montreal

During the second quarter of 1988 Montreal crude oil deliveries via IPL's Sarnia-Montreal pipeline and the Portland Pipe Line averaged 33 000 m^3/d, an increase of 9 000 m^3/d, or 40% from a year ago. Over 80% of the increase was in Canadian crude oil, as deliveries were up to almost 22 000 m^3/d while imports via Portland Pipe Line were up by 1 000 m^3/d to 11 000 m^3/d. The pipeline utilization rate was 41% for the Sarnia-Montreal line and 36% for the Portland-Montreal pipeline.

Figure 3.3.1

Crude Oil Deliveries to Montreal



Source: Energy, Mines and Resources and Interprovincial Pipe Line

In contrast to the first quarter, when most of the increase in the Sarnia-Montreal pipeline throughput was related to greater heavy crude oil deliveries, the second-quarter jump was concentrated in light crude oil, which was up almost 6 000 m^3/d, to 15 000 m^3/d. The additional deliveries of Canadian crude oil reflect, the additional upstream pipeline capacity added during the later part of 1987. Heavy crude deliveries were at 6 500 m^3/d, up 1 500 m^3/d. Partially processed oil deliveries fell by almost 50%, to less than 1 000 m^3/d.

More than half of the heavy crude oil deliveries were destined for the export market as producers sought market diversification and expansion. Most of the export sales were to the U.S. east and Gulf coasts, and to a lesser extent, Europe. Crude transfers to Canadian refiners via tanker from Montreal were over 3 000 m^3/d, in comparison with only 1 000 m^3/d last year. Most of the transfers occurred in April, in part, reflecting the end of refinery turnarounds.

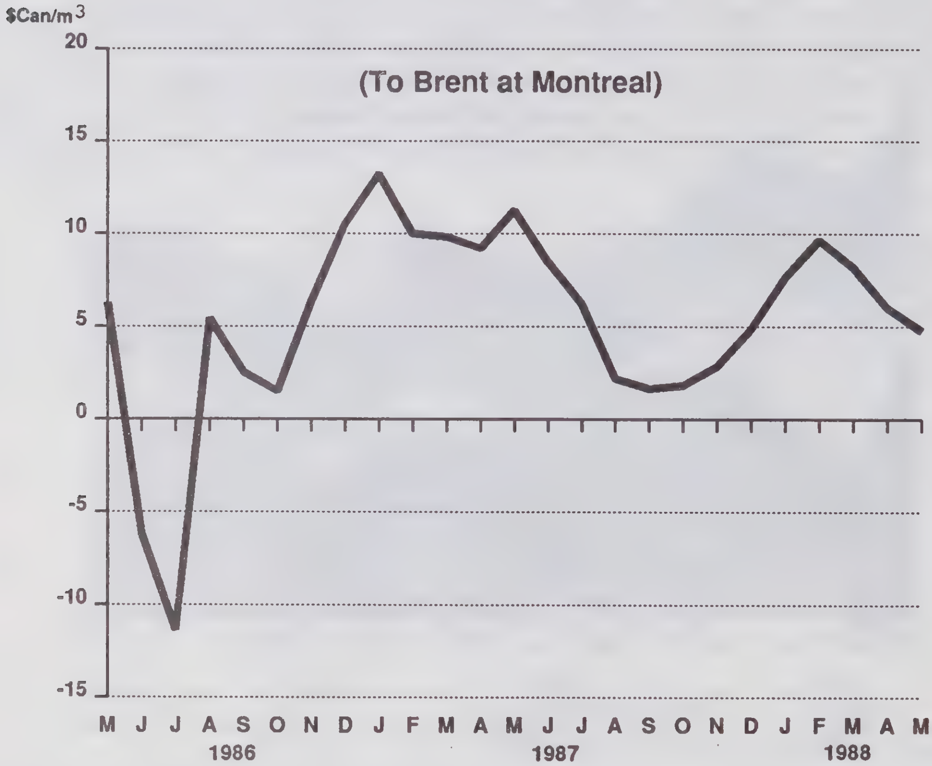
During the first half of 1988, estimated exports and transshipments were 7 000 m^3/d, up 4 000 m^3/d from the first half of 1987, accounting for one third of Sarnia-Montreal deliveries, the highest level in three years.

3.4 Montreal Crude Oil Economics

As illustrated in figure 3.4.1, since August 1986, Canadian light crude oil delivered to Montreal has had an apparent cost advantage over theoretical imports of North Sea Brent crude (based on a three months rolling average) particularly during the period November 1986 to June 1987 and again in late 1987 and early 1988. However, as shown in figure 3.4.2, despite the price advantage, Canadian deliveries of light domestic crude to Montreal have not necessarily reflected this advantage.

Figure 3.4.1

Canadian Light Crude Oil Price
Advantage/Disadvantage



Source: Energy, Mines and Resources

There are many factors, other than price, which influence the crude oil sourcing decisions of the Montreal refiners. Two of the most important over this period have been the need to maintain minimum throughput levels on both the Portland and Sarnia-Montreal pipelines, and upstream capacity constraints on the IPL system.

Throughout parts of the period, light crude deliveries were close to minimum managable levels. (Over the last year this has been less of a problem on the Sarnia-Montreal line because of increasing throughputs of heavy crude for export and transshipment.) With only two operating refineries in Montreal and minimum throughput concerns, a decision by either refiner to swing entirely to domestic or imported crude for whatever reason would have a significant impact on the operations of the other refiner. If the refiners switch to only one source, and the other pipeline shuts down they would, at least in the short term, lose an option regarding crude sourcing. To keep this option open, the refiners must therefore maintain minimum throughputs in both pipelines, which reduces the potential for switching, even if the price is clearly advantageous to one source.

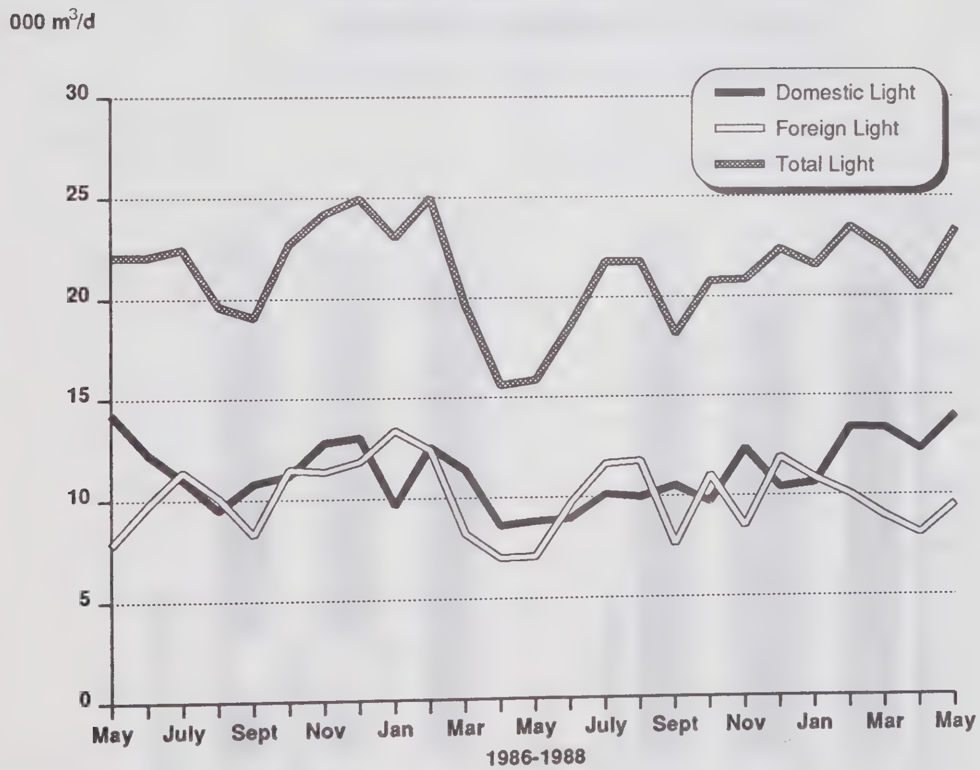
Pipeline space apportionment, (mainly in the period prior to June 1987), often resulted in Montreal refiners not having access to all of the domestic crude oil they may have been prepared to take. Since Ontario refiners had limited access to other crude sources, a portion of domestic light crude that might have gone to Montreal was delivered to Ontario with the Montreal refiners relying on other sources, such as foreign crude, stockdraw or product imports. Since mid-1987, capacity additions to the pipeline system have resulted in less severe apportionment, thereby making it easier for domestic crude to reach Montreal.

Other factors which have affected domestic light crude receipts include inventory change, the level of petroleum product imports, deliveries of partially processed oil and refinery maintenance programs. The refiners must also consider delivery reliability, price fluctuations, requirements for specific crude types, risk and quality considerations.

As a result of the influences (sometimes conflicting) of numerous factors, the specific effect of the theoretical price advantage is difficult to evaluate, and for the Montreal refiners, represents only one element, amongst many, to consider when making a purchasing decision.

Figure 3.4.2

Montreal Light Crude Oil Receipts



Source: Refiners' submissions to the National Energy Board

4. Crude Oil Supply and Disposition

4.1 Conventional Light Crude Oil Productive Capacity

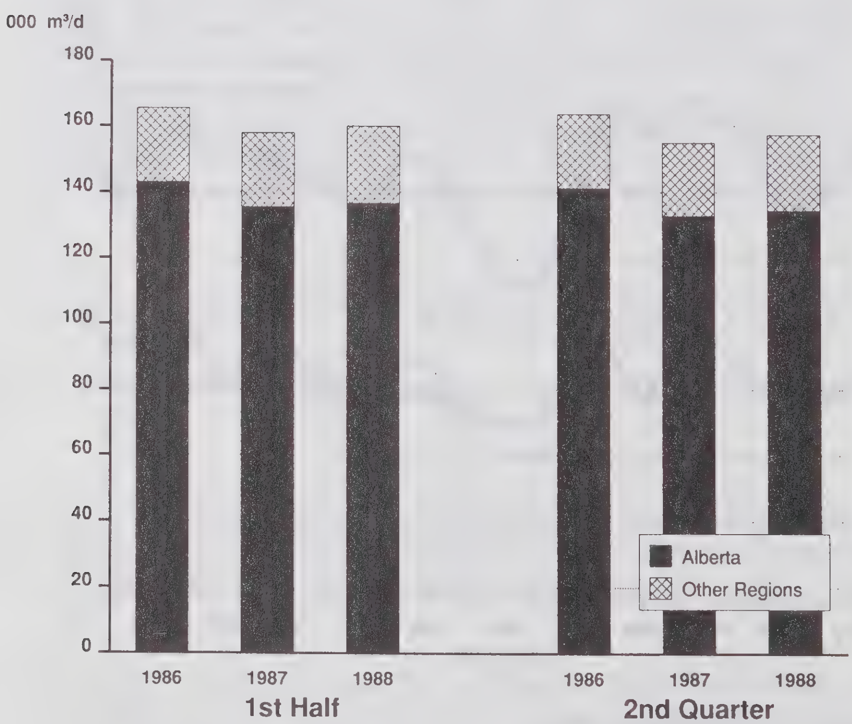
Alberta conventional light and medium crude oil productive capacity during the second quarter of 1988 continued to increase, up 2% to almost 135 000 m^3/d from a year earlier. This increase reflected Government incentives and the quasi-elimination of pipeline constraints (completion of IPL Phase III expansion and debottlenecking programs) which contributed to unforeseen higher productive capacity. During the first half of the year, Alberta light crude productive capacity recorded an increase of 1% to 137 000 m^3/d in contrast to the drop of 2 to 3% anticipated a year ago for this period.

Productive capacity in the second quarter outside of Alberta was ahead by almost 4% to 23 000 m^3/d, with most of the increase from Norman Wells in the Northwest Territories, where production rose by 20% to almost 5 000 m^3/d. This increase was largely as a result of greater storage capacity now available at the field.

Total conventional light crude oil capacity averaged 158 000 m^3/d and represented 82% of total available light crude oil supply, 1 percentage point higher than last year.

Figure 4.1.1

Conventional Light and Medium Crude Oil Productive Capacity



Source: National Energy Board

4.2 Light Crude Production and Disposition

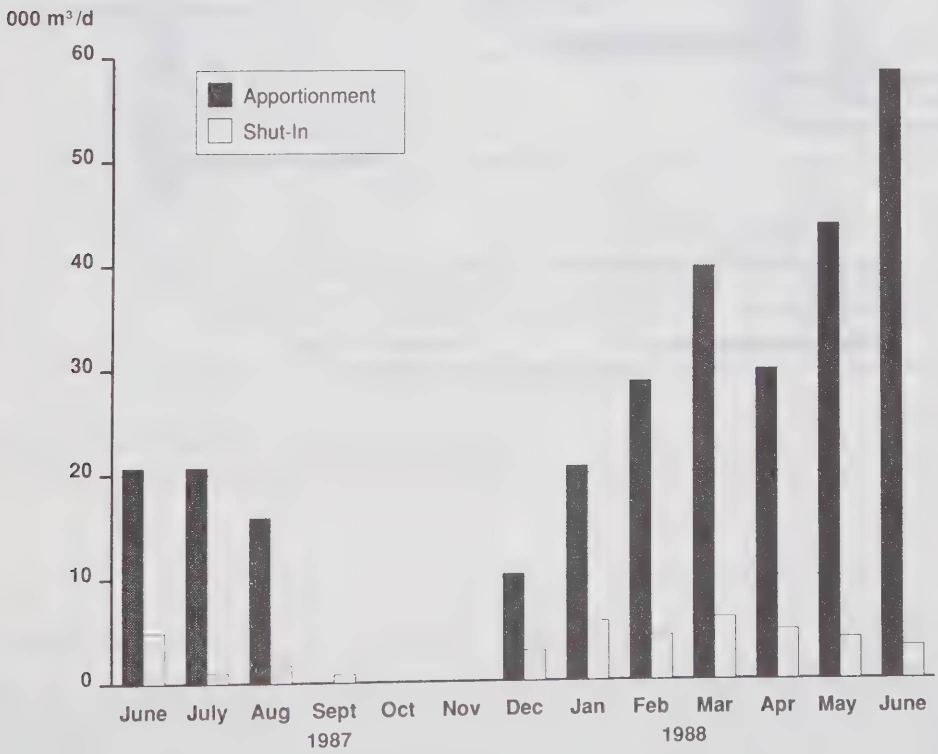
During the second quarter of 1988, IPL pipeline space apportionment reduced potential crude oil production, although the shortfall was much less than that experienced in 1987. The expansion of the IPL system and the introduction of the modified prorationing system resulted in total light crude oil and equivalent production (excluding pentanes plus as diluent) of 190 000 m^3/d, a 2% (4 000 m^3/d) increase over 1987. Light crude shut-in productive capacity was cut in half to 2 700 m^3/d.

Most of the incremental production occurred in Alberta where output was up 5% (6,000 m^3/d) to 132 000 m^3/d as producers responded to additional pipeline space and government incentives to bring on additional light crude oil capacity, despite the possibility of flat, or falling, crude oil prices. Production from other provinces at 23,000 m^3/d increased 4% from 1987 with higher output volumes produced in the North West Territories offsetting decreases in other regions, notably British Columbia. The combination of the above negated a 30% (2 000 m^3/d) drop in pentanes plus available as refiner feedstock. (See below)

IPL apportionment during the second quarter was generally related to overnominations, although increased light crude supply, seasonal pipeline maintenance and a scheduled maintenance shut-down of one major refinery in the Prairies also caused pressure on the IPL system. The overall impact on shut-in however, was marginal, since much of the apportionment reflected overnominations by shippers. Various industry and government committees continued to meet to explore ways to reduce the overnominations and capacity shortfalls as the forecast is for the IPL system to remain short of capacity by about 4 000 m^3/d to 6 000 m^3/d for the balance of 1988 and most of 1989.

Figure 4.2.1

IPL Apportionment and Shut-In



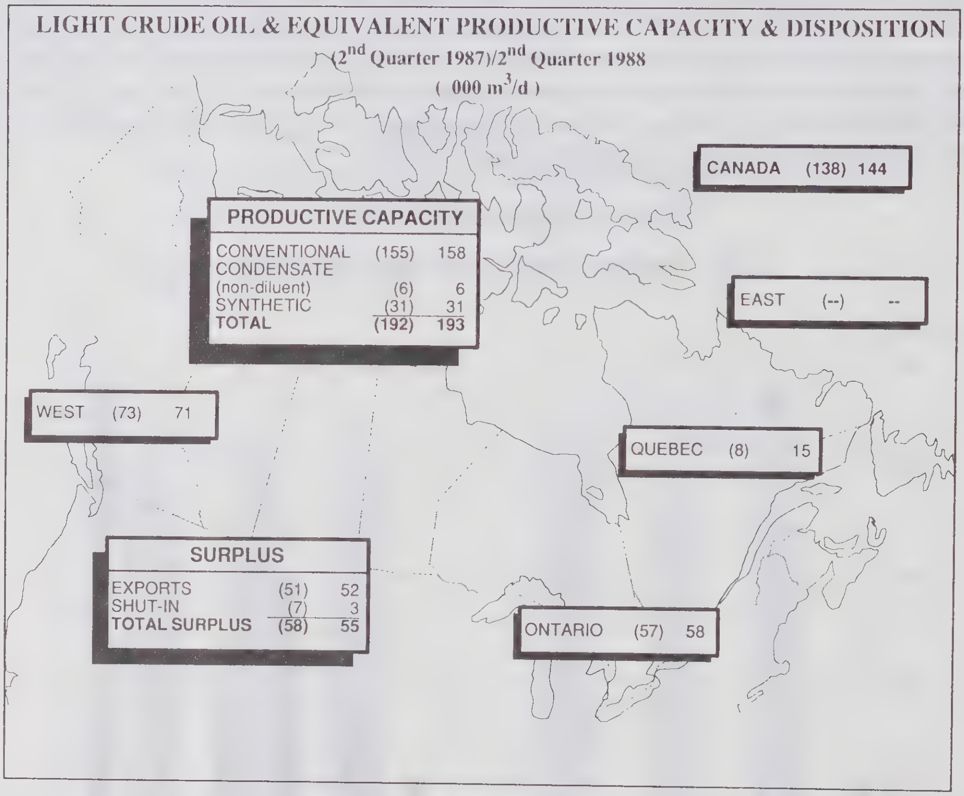
Source: Energy, Mines and Resources and National Energy Board

Because of the IPL capacity constraints, some production was brought to export markets through the Trans Mountain and Rangeland pipeline systems with the result that Trans Mountain was virtually at capacity and Rangeland had only about 3 000 m^3/d of spare capacity. However, given a choice, producers prefer to sell through the IPL system because of higher netback prices.

Synthetic crude production of 31 000 m^3/d was unchanged from the second quarter of 1987. This marked the first period since October 1987 that both plants were operating at 'normal' capacity. Full production is expected for the balance of 1988.

Pentanes Plus (condensate) production dropped slightly below the 16 000 m^3/d produced in the same period of 1987. Feedstock for refinery use continued to decline, down 2 000 m^3/d to less than 4 000 m^3/d, reflecting higher demand as heavy crude oil diluent.

Figure 4.2.2



Source: National Energy Board

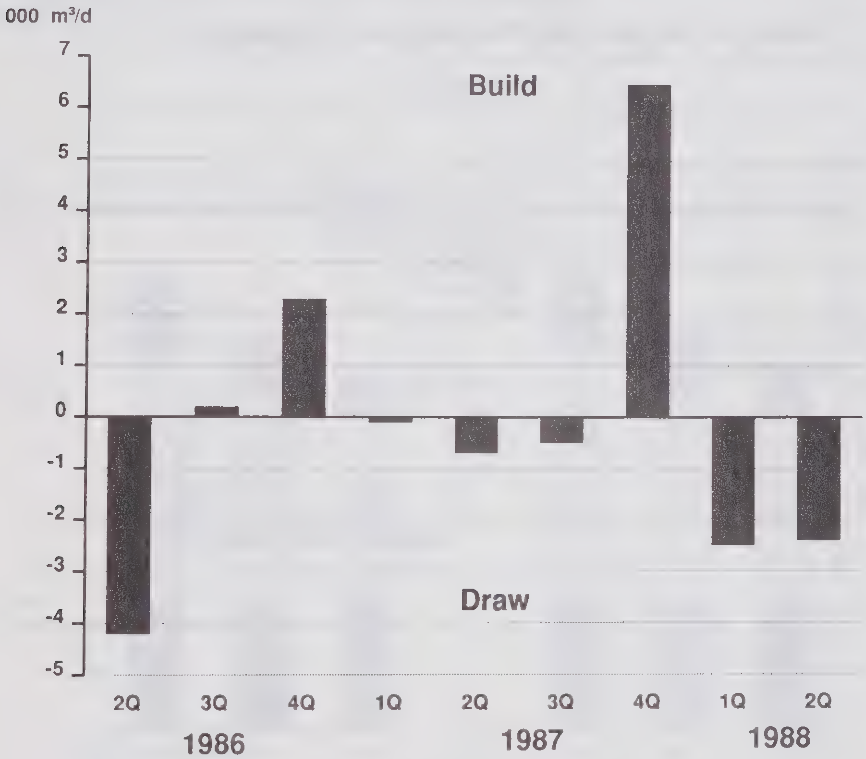
As illustrated in Figure 4.2.2, crude oil production does not always match disposition. The differences can be accounted for in several ways. The most obvious is the sometimes significant monthly and quarterly changes in heavy and light crude inventories that occur at the field and plant storage facilities of the upstream producers and in the storage tanks of the pipeline companies. According to Energy, Mines and Resources (EMR) estimates the cumulative upstream light crude oil drawdowns for the second quarter of 1987 and 1988 amounted to 67 200 m^3 and 216 100 m^3, or 740 m^3/d and 2 375 m^3/d, respectively (see Figure 4.2.3). In comparison, per diem drawdown required to balance production with disposition over the same two quarters were virtually nil in 1987 and 2 200 m^3 in 1988.

One factor affecting the discrepancy between the estimates of actual inventory changes and those inventory changes required for 'balance sheet' consistency may be the variety of data sources used. For example, information pertaining to production capacity is normally provided by the upstream producers while disposition data comes from the refining sector.

Problems of definition and timing invariably arise under such circumstances, given the differing nature of operation of the upstream and downstream sectors. Moreover, for the sake of timeliness, preliminary data, subject to eventual revision, is often incorporated into the statistics.

Figure 4.2.3

Estimated Upstream Light Crude Oil Inventory Changes*



in field, plant and pipelines

Source: Energy, Mines and Resources and pipeline companies

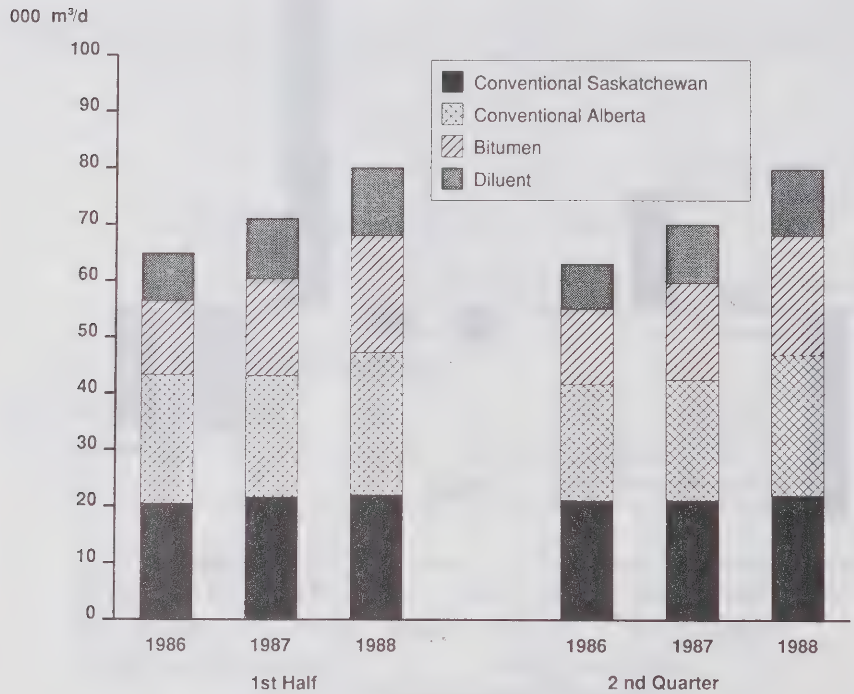
In recent periods (last 9 quarters) the differences between light crude oil and equivalent production and disposition and the corresponding inventory changes at the field and in pipeline tanks has been consistent, with inventory changes generally accounting for all but about 1 000 m^3 (or 0.6% of production) of production/disposition discrepancies. However, in some periods prior to 1986 the data relationship has been less congruent, especially with respect to heavy crude (see Section 4.4). The above-mentioned "other factors' may be more prevalent in those cases.

4.3 Heavy Crude Oil Productive Capacity

Unblended conventional heavy crude oil productive capacity during the second quarter of 1988 averaged 47 000 m^3/d, up 12% from a year ago. (It is expected to increase by an additional 1 000 m^3/d during the remainder of the year.) This increase largely reflects higher drilling activity in the Bow River area, in part because of improvements in enhanced oil recovery techniques. Historically, Saskatchewan's share of conventional heavy crude oil exceeded that of Alberta, however, most of the recent capacity additions have been in Alberta, reversing that trend. Alberta's market share was 54% during the second quarter and the first half of 1988, which represented an increase of 5 and 3 percentage points respectively, from last year.

Figure 4.3.1

Heavy Crude Oil Productive Capacity



Source: National Energy Board

'Raw' bitumen capacity was at 21 000 m^3/d, an increase of 22%, representing the highest bitumen level ever recorded. This increase reflects the completion of several projects in conjunction with lower operating costs and more favorable fiscal and tax incentives from governments. These developments offset some of the impact of lower prices on production. Most of the additional bitumen capacity was from Cold Lake, reflecting the completion of Phase VII and VIII and some technological improvements related to the previous phases. Currently, bitumen output represents 30% of total unblended heavy crude oil, up 2 percentage points from a year ago. As a result of the continuing increase in bitumen supply, diluent requirements for blending purposes increased by 20% to almost 12 000 m^3/d.

Total blended heavy crude oil productive capacity averaged 81 000 m^3/d, representing 30% of total available supply of Canadian crude oil and equivalent.

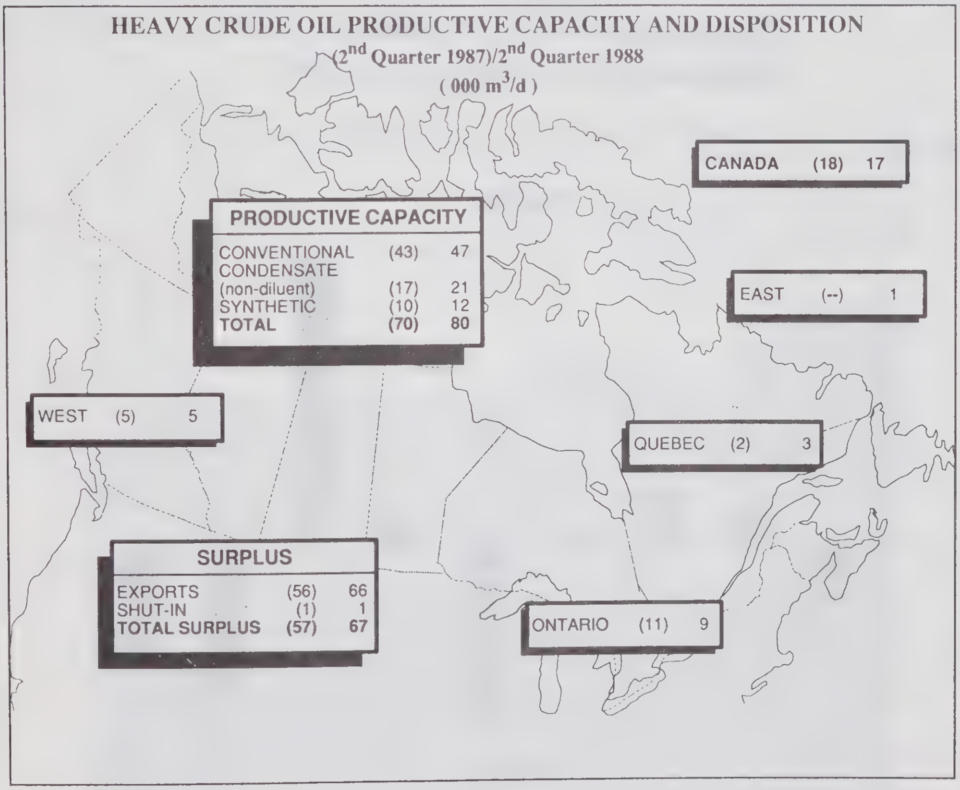
4.4 Heavy Crude Oil Production and Disposition

Blended heavy crude production reached 80 000 m^3/d, a 15% (10 000 m^3/d) jump from the second quarter of 1987. In conventional heavy crude, a 9% (4 000 m^3/d) increase was recorded, all from Alberta (mainly the Bow River area), bringing total production in this category to 46 000 m^3/d.

Bitumen production jumped almost 25%, to 21 000 m^3/d, 4 000 m^3/d more than in 1987. To enable this crude to be moved, additional diluent was required, for a total of over 12 000 m^3/d, up almost 20% (2 000 m^3/d). As was the case in 1987 a small amount of heavy crude productive capacity was shut-in.

Domestic deliveries of heavy crude were 17 800 m^3/d, similar to that in 1987, with exports accounting for the balance. (See Section 5 for further discussions on exports)

Figure 4.4.1



Source: National Energy Board

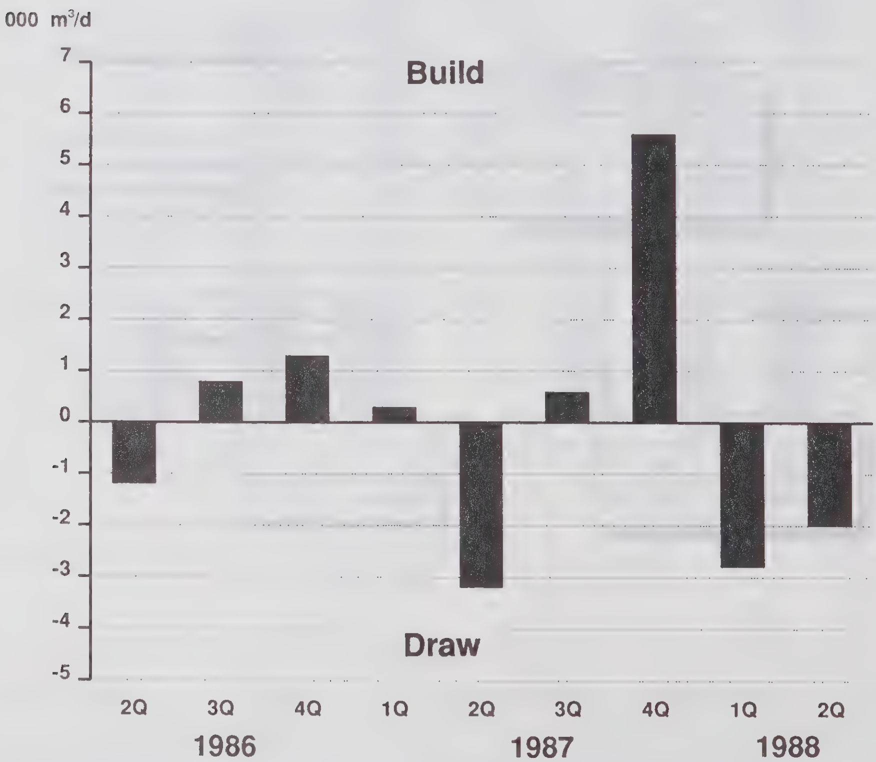
The heavy crude oil upstream stock drawdowns for the second quarters of 1987 and 1988 were estimated to be 295 000 m^3 and 181 000 m^3, or 3 240 m^3/d and 1 990 m^3/d respectively (figure 4.4.2). However, the average daily drawdowns necessary to reconcile production with disposition over the same two periods were 5 800 m^3/d and 3 700 m^3/d.

Reasons for the lack of congruence beween necessary and actual inventory changes have been suggested in the previous section on light crude, and appear particularly applicable in the case of heavy crude oil where larger discrepancies have generally existed. Between the second quarter of 1986 and 1988 approximately 3,200 m^3/d in heavy crude production and disposition discrepancies (or approximately 5% of production) cannot be accounted for by inventory change.

The problem of definition may be particularly relevant in the heavy crude category. For example, inaccuracies may develop in determining blended heavy crude volumes (which include recycled diluent), or light crude and partially processed crude may be inadvertently included in the heavy crude category from time to time.

Figure 4.4.2

Estimated Heavy Crude Oil Upstream Inventory Changes*



** in field, plant and pipelines*

Source: Energy, Mines and Resources and pipeline companies

5. Exports and Imports

5.1 Crude Oil Exports

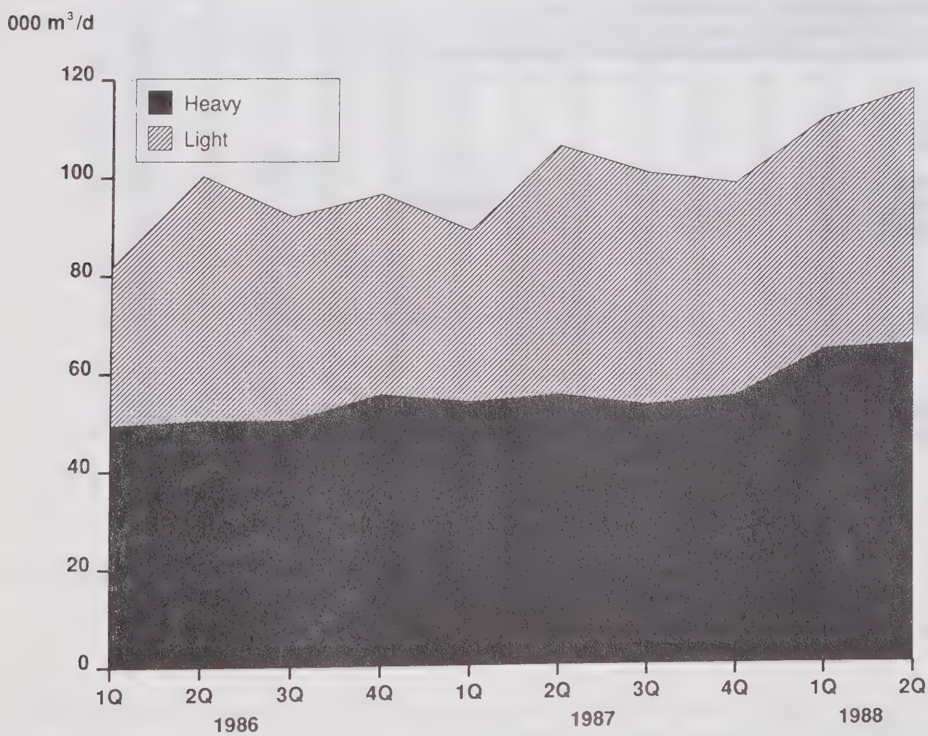
Total crude oil exports for the second quarter of 1988 averaged 118 000 m^3/d, about 12 000 m^3/d (11%) over the same period a year earlier. Of this volume, exports to the United States increased by about 8 000 m^3/d (7%) to 114 000 m^3/d while offshore exports to such destinations as Japan, Malaysia, Taiwan and Thailand increased significantly on small volumes to just over 4 000 m^3/d.

The increase in crude oil exports during the quarter was largely due to the continuing strength of U.S. refinery demand; the increased availability of Canadian crudes for export, in particular heavy crudes as a result of 'debottlenecking' and expansion programs at various in situ oil sands projects; additional pipeline capacity to U.S. markets; and a continuing pursuit by producers of market diversification in the United States and offshore.

As a percentage of total Canadian crude oil production, second-quarter exports represented about 43% of production, up 3 percentage points from last year (heavy production 79%, light 25%). Exports were split at a ratio of 56:44 between heavy crudes and light and equivalent crudes compared with a 53:47 ratio a year earlier. In volumetric terms exports of heavy increased by 10 000 m^3/d (18%) to nearly 66 000 m^3/d, while light and equivalent crudes increased by only 2 000 m^3/d.

Figure 5.1.1

Crude Oil Exports (Light/Heavy)



Source: National Energy Board

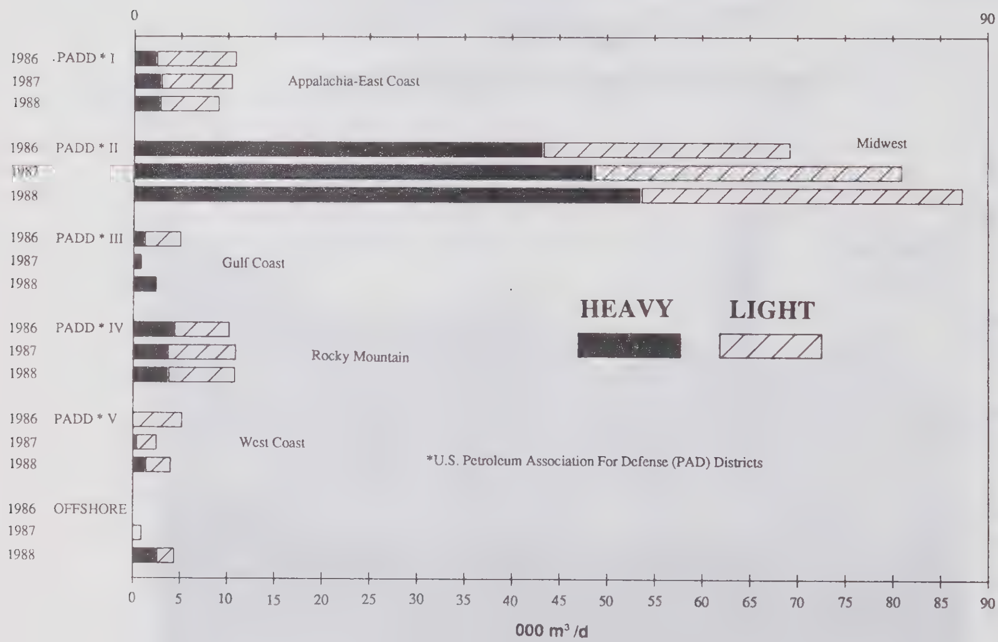
As illustrated in Figure 5.1.2 Canada's 'traditional' northern U.S. markets, east of the Rocky Mountains (Petroleum Administration for Defense (PAD) Districts I-IV*), received 110 000 m^3/d, up 7% from a year earlier, while the remaining 4 000 m^3/d, was delivered to PAD District V on the west coast of the United States. About 6% of total exports to the United States during the second quarter (up slightly from last year), were delivered by tanker via the ports of Montreal and Vancouver, to various 'non-traditional' markets, in particular to PAD District I and III destinations along the eastern seaboard and the Texas Gulf Coast.

As in the past, PAD District II, mainly the Minnesota/Wisconsin and Chicago, Illinois refining areas, received the largest share of Canadian pipeline-connected crude oil exports. Second-quarter deliveries averaged 87 000 m^3/d, about three-quarters of all Canadian exports to the United States. Heavy crude oil receipts, in part, because of increased supply of heavy crudes (bitumen) rose by 10% to 53 000 m^3/d, while light crudes increased by 3% to 34 000 m^3/d

Figure 5.1.2

Light and Heavy Crude Oil Exports by Destination

(Second Quarter)



Source: Energy, Mines and Resources and National Energy Board

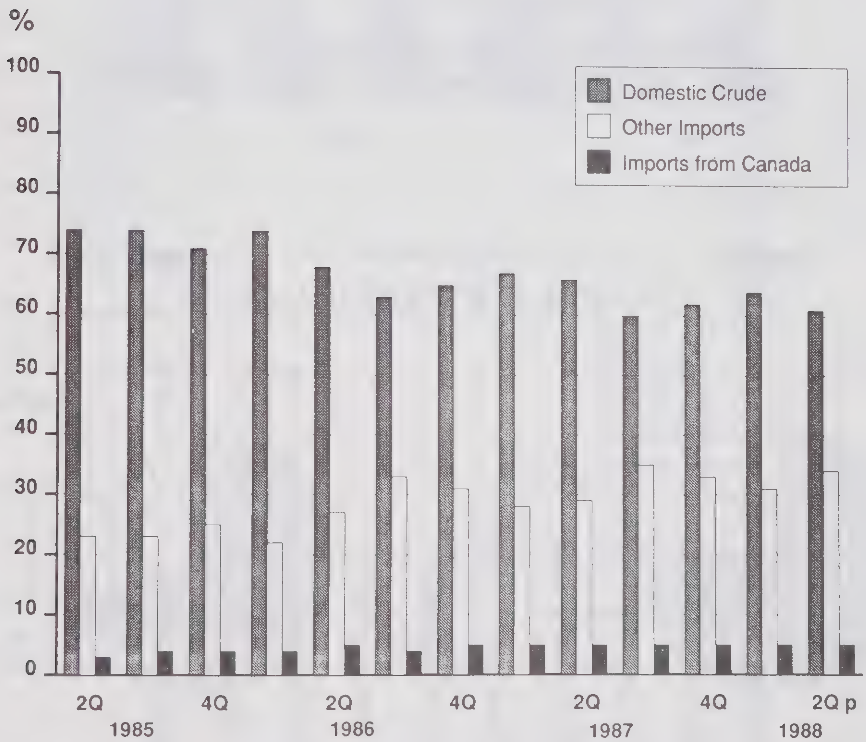
Although the Chicago refinery area is the largest recipient of Canadian crudes (about 65%), most of PAD District II's second-quarter increase occurred in the Twin Cities area. Total receipts for the second quarter rose by 22%, to 32 000 m3/d from a year earlier. Heavy crudes accounted for the largest proportion of this increase, as receipts jumped by 18% to 27 000 m3/d. Light crudes were up just over 50%, to 5 000 m^3/d.

While PAD District II registered the largest volumetric increase in the receipt of Canadian crudes, most other PAD Districts maintained, or marginally increased, their receipts on small volumes. Demand in Canada's second largest market, PAD District IV, the Montana and Wyoming refining areas, remained at about 11 000 m^3/d, with the proportion of heavy to light crudes at 33:67.

Since the deregulation of the Canadian oil market (June 1985), total exports of Canadian crude oil to the United States have increased by about 75%. Relative to 'other' imports to the United States (see Figure 5.1.3) Canada has maintained and improved its overall U.S. market share, despite Interprovincial Pipe Line (IPL) capacity constraints which forced apportionment of volumes exported throughout much of this period. Over the last three years, total U.S. imports of crude oil (excluding NGLs and other feedstocks), as a percentage of U.S. refinery demand, have grown from about a 25% to a 40% share, as U.S. indigenous supply decreased (about 11%) and refinery demand rose (7%), reflecting the growth in product consumption.

Figure 5.1.3

Canadian Share of the U.S. Market



Source: Energy, Mines and Resources and U.S. Energy Information Administration

Canada's total market share of U.S. refinery demand has increased from 3% (65 000 m^3/d) to 5% (114 000 m^3/d) over the last three years, primarily due to increased demand from the 'traditional' northern refining areas served by the IPL. However, aggressive price competition within the U.S. market by 'other exporters' such as OPEC and Mexico has led to an almost proportional growth (+ 50%) in their total market share relative to Canadian crude, from 23% to about 34%. (In contrast the derived market share for indigenous U.S. crude fell from 74% to 61%.) The increase in 'other exporters' share has occurred for the most part in those refining areas such the U.S. east coast and Texas/Louisiana Gulf Coasts not readily accessible to Canadian crude.

5.2 Crude Oil Imports

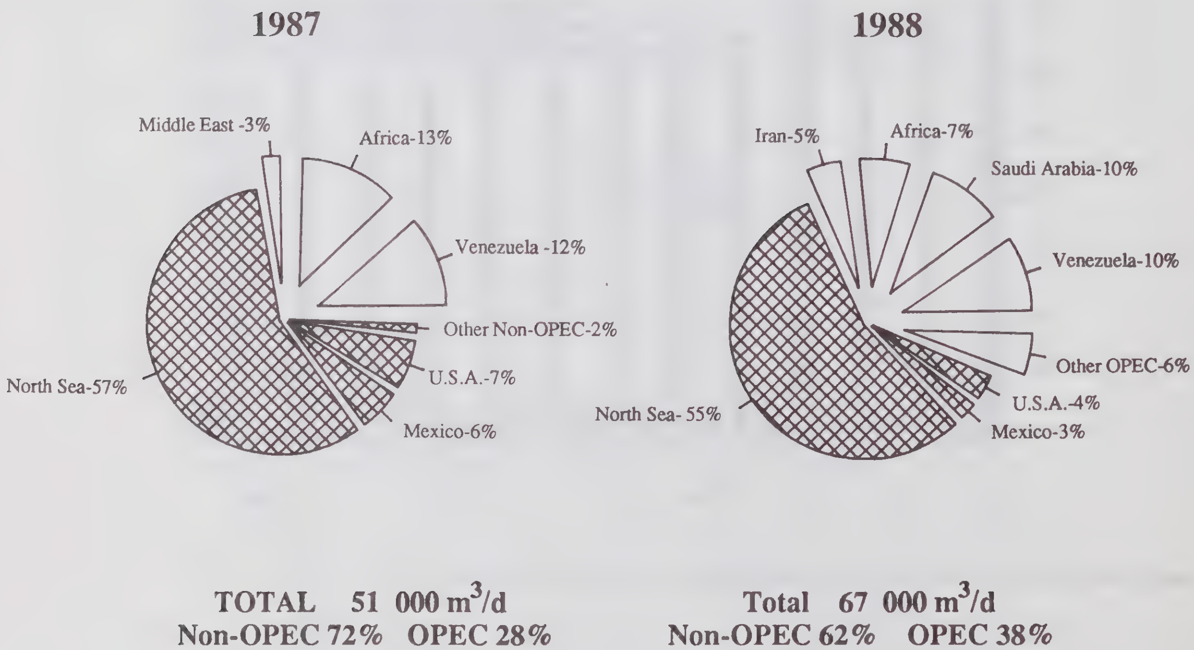
Canadian refiners imported 67 000 m^3/d of foreign crude oil during the second quarter of 1988, 30% (16 000 m^3/d) more than in the same period of 1987. A large portion of the increase reflected Come-by-Chance requirements which were non-existent a year earlier.

OPEC's share of foreign supply increased 10 percentage points to 38%, or in volumetric terms from 12 000 m^3/d to 26 000 m^3/d. In contrast to the second quarter of 1987, when no crude oil was received from Saudi Arabia and Iran, refiners took delivery of 6 000 m^3/d and 3 000 m^3/d respectively, from these countries. Other OPEC sourcing was virtually unchanged, with Venezuela the largest single OPEC supplier, at 7 000 m^3/d.

Non-OPEC crude receipts, although lower in percentage terms, increased marginally to 42 000 m^3/d. The North Sea continued to account for the majority of Canadian foreign receipts with 55% of the total, the same as in 1987. Imports from the United States at 2 000 m^3/d were 34% lower than a year ago, while those from Mexico dropped 22% to 2 000 m^3/d.

Figure 5.2.1

Sources of Crude Oil Imports
(Second Quarter)



Source: National Energy Board

On a regional basis, Atlantic imports of 41 000 m^3/d were 55% higher than in 1987, part of which was for the additional refinery. Quebec had foreign receipts of 23 000 m^3/d and Ontario 2 000 m^3/d, almost unchanged from a year earlier.

Figure 5.2.2

Crude Oil Imports by Region

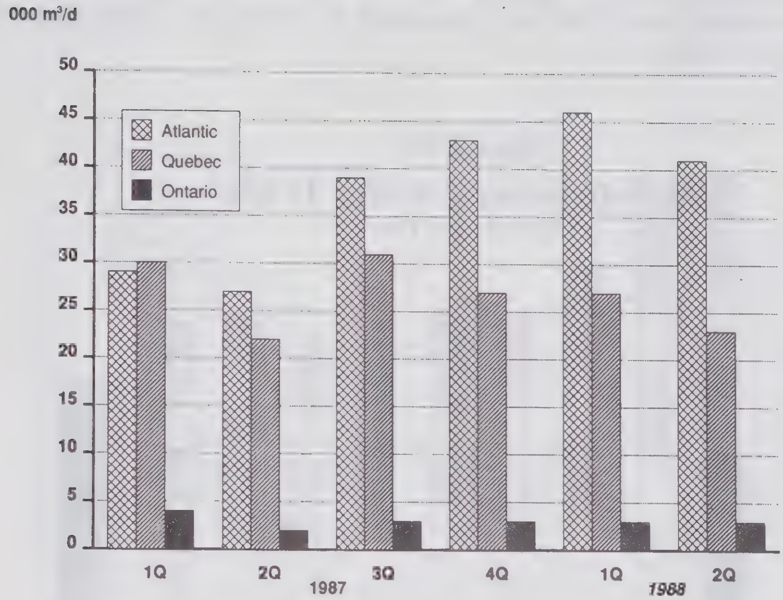
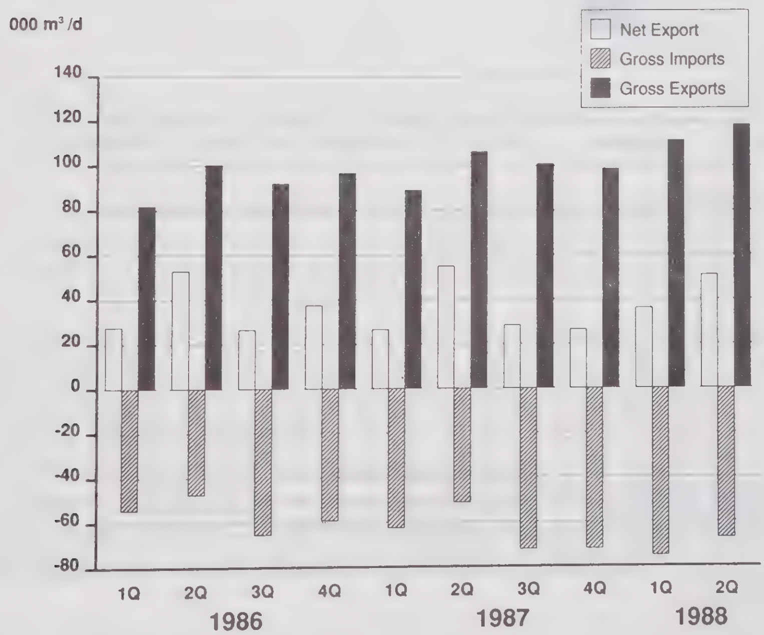


Figure 5.2.3

Crude Oil Exports & Imports



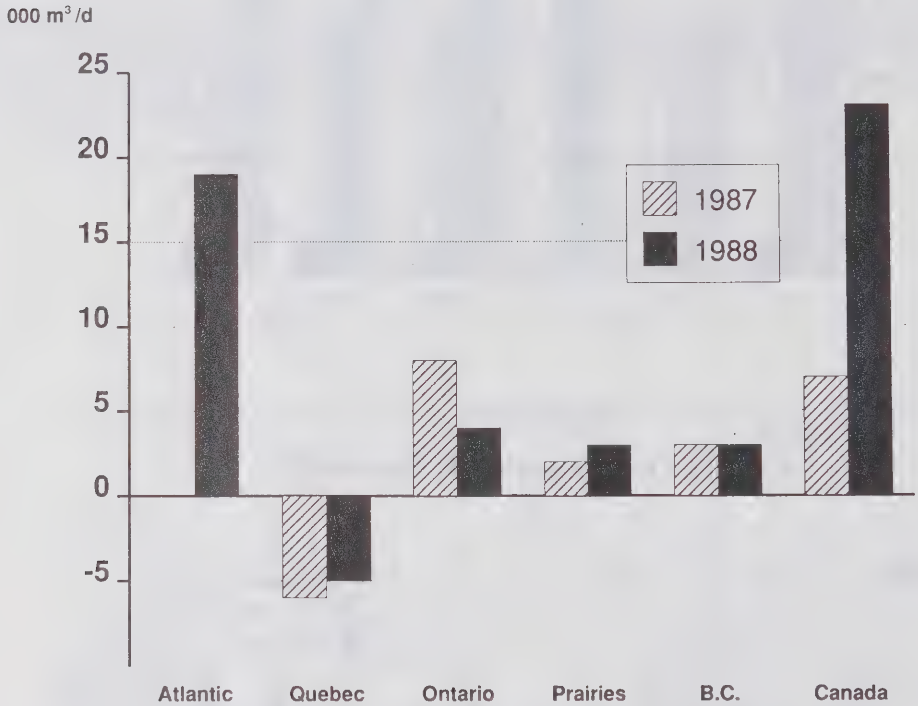
Source: Refiners' submissions to the National Energy Board

5.3 Petroleum Product Trade

Largely as a result of the reactivation of the Newfoundland refinery under a crude import and product export agreement, the Canadian trade surplus in oil products during the second quarter continued to increase. It more than tripled, from 7 000 m^3/d to almost 23 000 m^3/d. There was also a decline in product imports in eastern Canada.

Figure 5.3.1

Net Petroleum Product Trade
(second quarter)

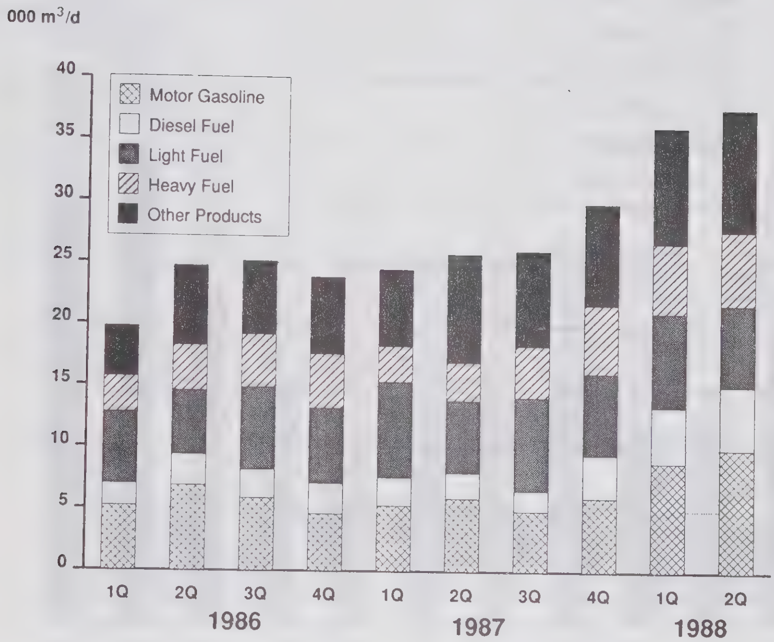


Source: Statistics Canada

As illustrated in Figure. 5.3.1, trade on a regional basis followed the historical trend, with all regions experiencing surpluses except Quebec. The Atlantic region recorded the largest surplus, at 19 000 m^3/d, while the Prairies and British Columbia were each about 3 000 m^3/d each. Only in Ontario did the surplus decline, down 50% to 4 000 m^3/d, reflecting unusually high exports last year because of favorable U.S. market conditions.

Figure 5.3.2

Product Exports



Source: Statistics Canada

Gross petroleum product exports totalled 38 000 m^3/d, an increase of 12 000 m^3/d from a year ago. Atlantic exports accounted for almost two thirds of the total.

Despite an increase in all product categories, the composition of exports remained relatively unchanged from last year. Motor gasoline (mainly from the Atlantic region) accounted for more than a quarter of total exports followed by light and heavy fuel oil, both at around 16% of the market.

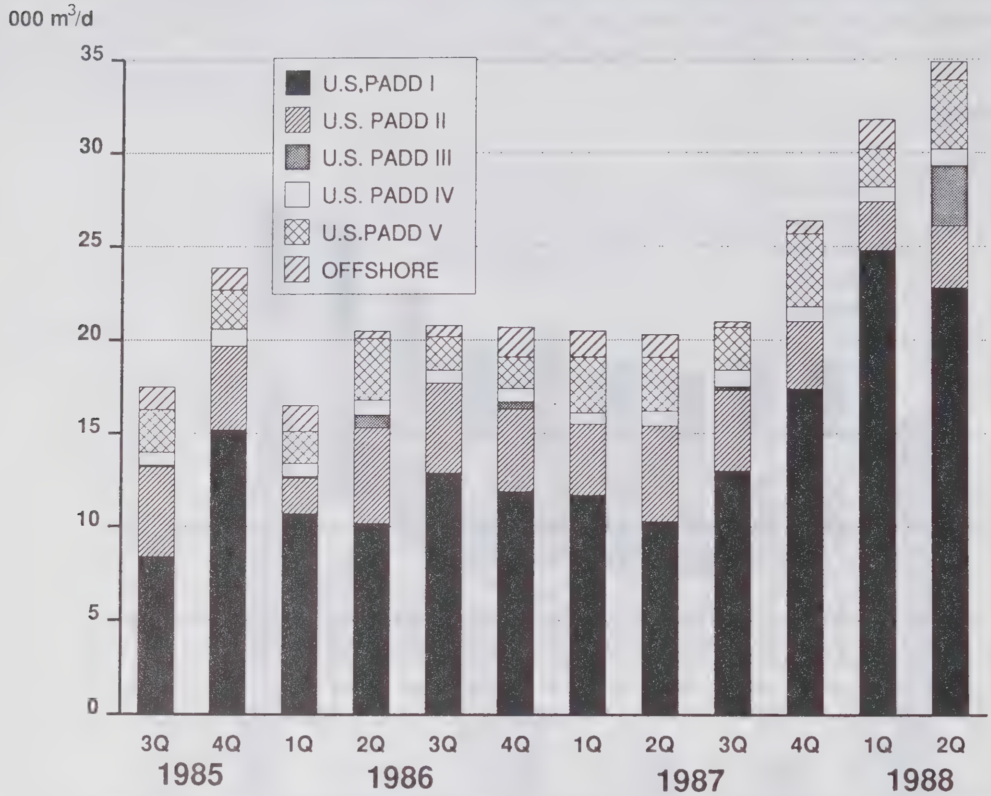
Heavy fuel oil exports, however, doubled from a year ago, with all of the increase in the Atlantic region, where exports increased from an insignificant volume last year to almost 4 000 m^3/d. Exports from Quebec and Ontario, however fell, in part, as a result of more stringent New York state sulphur emission standards, which limited potential exports.

Petrochemical feedstock and jet fuel recorded substantial declines, down 30% and 18% to 1 000 m^3/d and 3 000 m^3/d, respectively. 'Other products' exports (including lube oil, asphalt, propane, etc) were ahead by 2 000 m^3/d, to 6 000 m^3/d and accounted for 16% of total exports.

Sales to the United States made up about 97% of the 35 000 m^3/d of Canadian main petroleum product exports during the second quarter of 1988. PAD District I accounted for 65% (or 23 000 m^3/d) of the U.S. total, up 15 percentage points (12 500 m^3/d). (Refined products produced at the Come-by-Chance refinery are exported to the northeastern U.S. As a whole, about three quarters of exports to PAD District I exports are under processing agreements.)

Figure 5.3.3

Main Petroleum Product Exports by Destination*



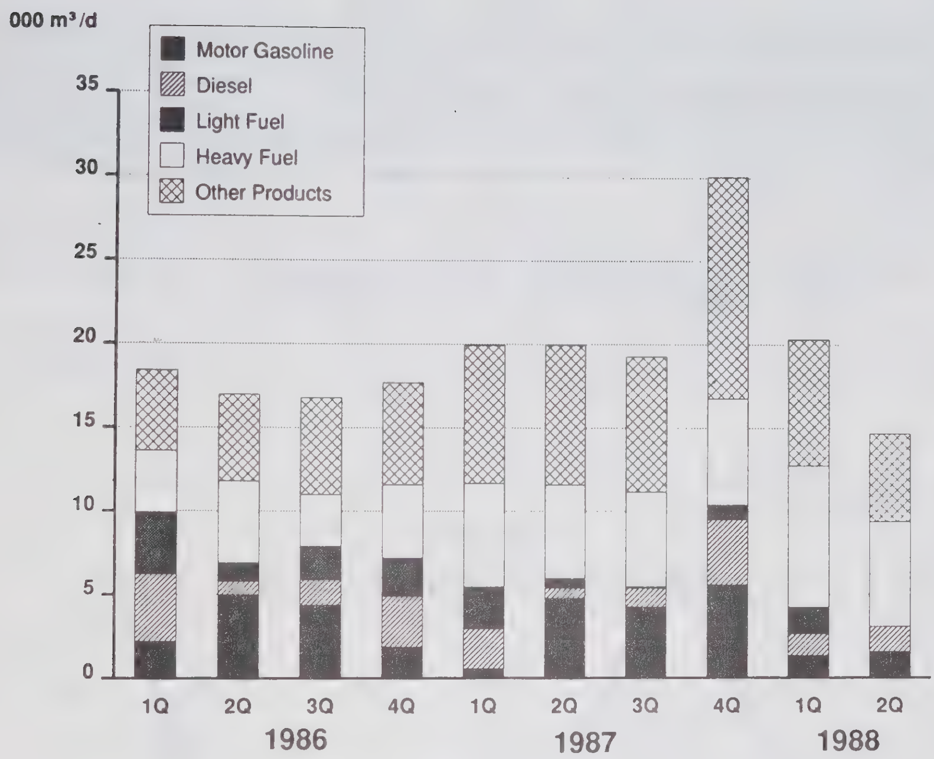
** excludes some products included under Statistics Canada definition, e.g; lubricants*

Source: National Energy Board

Of the 310 000 m^3/d of products imported by the United States, Canadian products (excluding liquified petroleum gases) represented 11% of total receipts. Venezuela was the largest supplier with 15% of U.S. imports followed by the Virgin Islands and Canada.

Figure 5.3.4

Product Imports



Source: Statistic Canada

Gross petroleum product imports averaged 15 000 m^3/d, down 18% from last year. Quebec imports accounted for almost 50% of the total volume imported, but deliveries there dropped by 21% from last year. British Columbia imports were up by 1 000 m^3/d to 1 500 m^3/d reflecting higher petroleum product consumption.

Heavy fuel oil made up around 43%, (up 15 percentage points) of imports. Approximately 60% of the heavy fuel oil imports were to the Atlantic, reflecting high demand for thermal electricity generation. 'Other products' accounted for almost 36% of total imports of which the largest component, petroleum coke represented about 15% of overall product imports. Most of these coke imports are used in heavy industry such as steel.

5.4 Net Light and Equivalent Crude Oil Export Position

Since 1984, when light crude oil export restrictions were loosened, Canada has been a net exporter of light crude oil and equivalent (including light petroleum products). However, as illustrated in Figure 5.4.1, the net export position in 1986 and 1987 declined as a result of imports increasing more rapidly than exports. This increase in crude oil imports reflects the impact of crude oil price deregulation, including the elimination of transshipment subsidies for domestic crude. On the export side, exporters faced pipeline constraints and a flat to negative growth in the production of conventional light crude oil.

Figure 5.4.1

Net Light Crude Oil Trade Position

Source: Statistics Canada and Energy, Mines and Resources

During the second half of 1987, Canada became a net importer of light crude oil and equivalent again, primarily because of an increase in crude imports for the Come-by-Chance refinery (without an offset in product exports), and sharply higher petroleum product imports during the fourth quarter, as a result of attractive prices. In the first half of 1988, however, net light oil exports climbed to 11 000 m^3/d reflecting an increase in exports of crude oil and petroleum products. Higher pipeline capacity and increased Canadian supply, accounted for much of the improvement in crude exports. Crude imports were also up substantially but there was an offsetting increase in product exports.

6. Energy Trade Balance

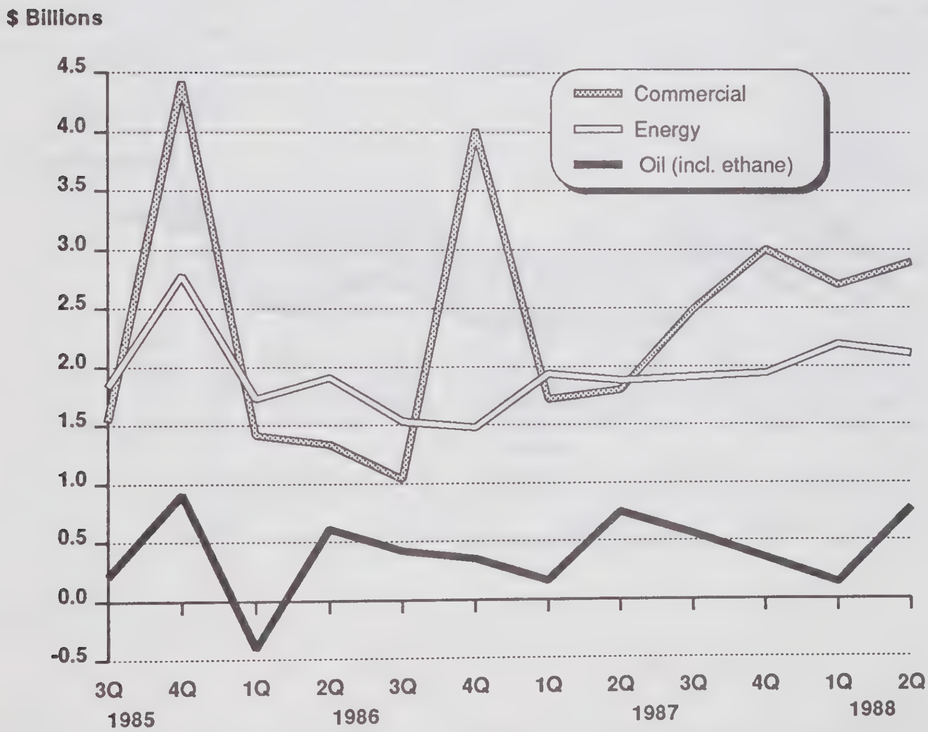
6.1 International

Based on preliminary data from Statistics Canada, the Canadian energy trade surplus in the second quarter of 1988 was estimated at $2.1 billion, an increase of $215 million (11%) from a year ago, but marginally lower than the previous quarter. Crude and petroleum products accounted for the largest share (37% or $783 million) of the energy surplus, and accounted for the largest increase, up 20%, mainly as a result of an increase in net petroleum product exports. Natural gas contributed $630 million (30%) to the trade surplus, a jump of 14% from 1987. Liquified petroleum gases and coal also recorded increases which were offset by a corresponding declines in electricity and uranium. The improvement in the trade surplus primarily reflected higher volumetric sales to the United States, rather than higher prices.

Despite a marginal improvement in the oil trade surplus, the oil share of the overall commercial trade balance fell from about 40% to 25% as a result of the substantial increase in the commercial trade balance.

Figure 6.1.1

Oil and Energy Trade Balance



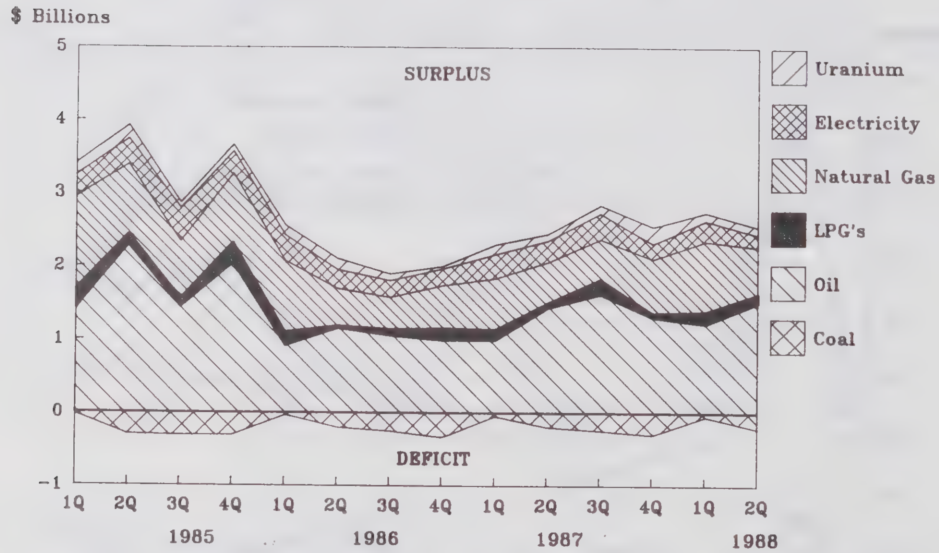
Source: Statistics Canada

6.2 United States

At $2.4 billion (up 21% from a year ago) Canada's energy trade surplus with the United States represented over 80% of our commercial trade balance. Virtually all the improvement was related to oil, which rose from $1.1 billion to $1.5 billion, and accounted for 63% of energy trade with the United States. An increase in crude oil exports and a more than the doubling of product exports from the Atlantic (see Section 5.3) accounted for much of the improvement. This upward shift on the product side is expected to continue in the long term. However, there will be an offsetting deterioration in trade with other countries because of the offshore crude imports required for the product processing agreements. Trade in natural gas also recorded a substantial increase while all other categories registered declines. The largest drop occurred in electricity (down $120 million) as result of higher domestic demand. Coal continued to register a deficit ($200 million). The overall trade surplus grew much more rapidly on a volumetric basis than on a value basis reflecting sliding prices and a strong Canadian dollar.

Figure 6.2.1

Net Energy Commodity Trade with the U.S. (Value)



Source: Statistics Canada

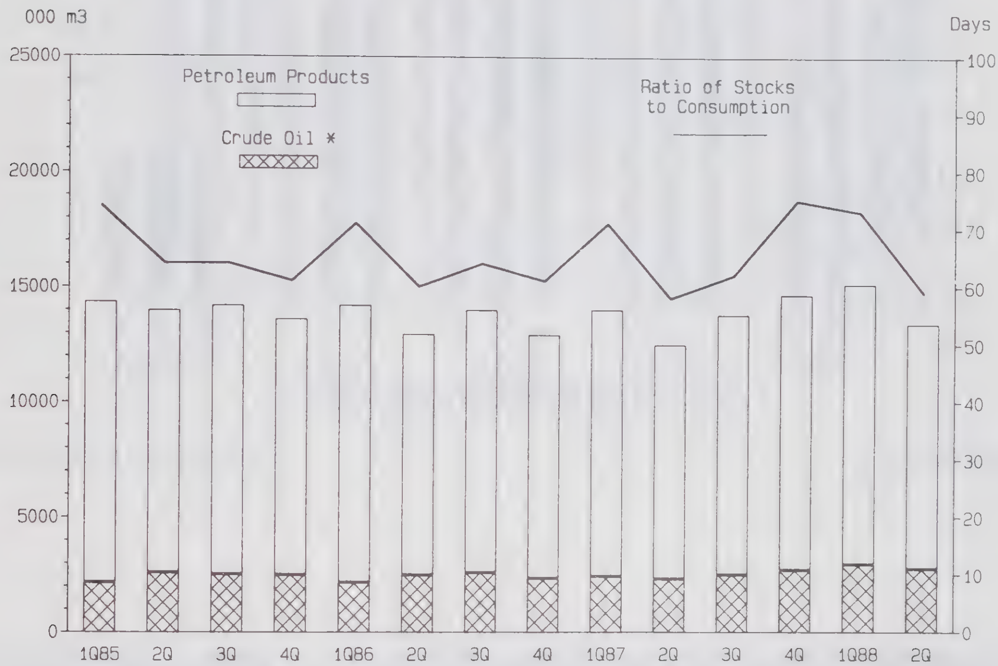
7. Stocks

Refined petroleum products and crude oil inventories at the end of the second quarter reached 13.4 million cubic metres, 7% higher than the same period a year earlier. Just over half of this increase can be attributed to crude oil inventories which rose 17% to 2.7 million cubic metres (most of which occurred in the Atlantic region), while petroleum product rose 5%, to 10.7 million cubic metres. Large increases in diesel and heavy fuel oils of 20% and 40% respectively, were offset somewhat by a 4% decrease in motor gasoline and a 15% decrease in light fuel oils.

Figure 7.1.1

Closing Crude and Product Inventories in Canada

(end of each quarter)



** excludes crude in pipelines and tankage*

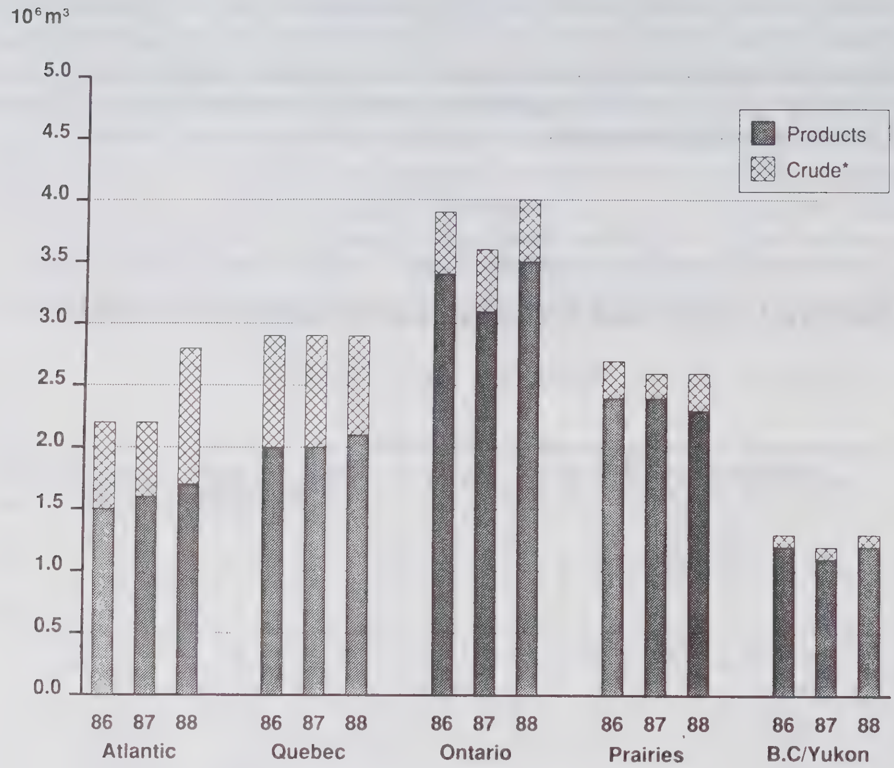
Source: Statistics Canada

The increase in total crude oil inventories was primarily a result of a near doubling of crude inventories in the Atlantic region, to about 1 million cubic metres while all other regions marginally adjusted crude levels. For the most part, this increase can be attributed to the start up of the Come-by-Chance refinery (about one quarter of the increase) and to fluctuations in crude oil delivery times (tanker versus pipeline).

Petroleum product inventories increased in all regions except in the Prairies. Ontario product inventories increased by 12%, to 3.5 million cubic metres, led by a 13% and 25% jump in motor gasoline and diesel fuel. The Atlantic, Quebec and British Columbia regions each increased their product inventories by about 1 million cubic metres, while in the Prairies inventories decreased by about the same amount.

Figure 7.1.2

Closing Inventories by Region - June



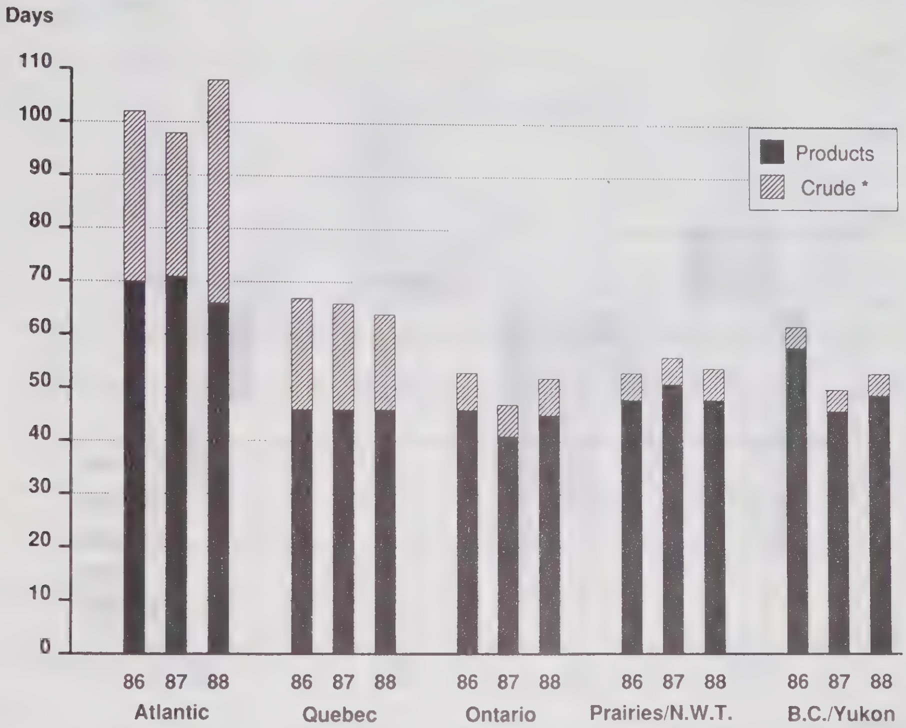
** excludes crude in pipelines and tankage*

Source: Statistics Canada

By the end of the quarter, the ratio of stocks to consumption (petroleum products plus crude oil) reached 59 days one day higher than in the same period a year earlier. The Atlantic region continued to maintain its position of holding the highest level of inventories relative to consumption, up 10 days from last year, to 108 days, although part of increase reflects an increase in product stocks (mainly for export purposes) at the Come-by-Chance refinery. Ontario and British Columbia were the only other regions to have any appreciable increase in the ratio while Quebec and the Prairies declined marginally.

Figure 7.1.3

Ratio of Stocks to Consumption



** excludes crude in pipelines and tankage*

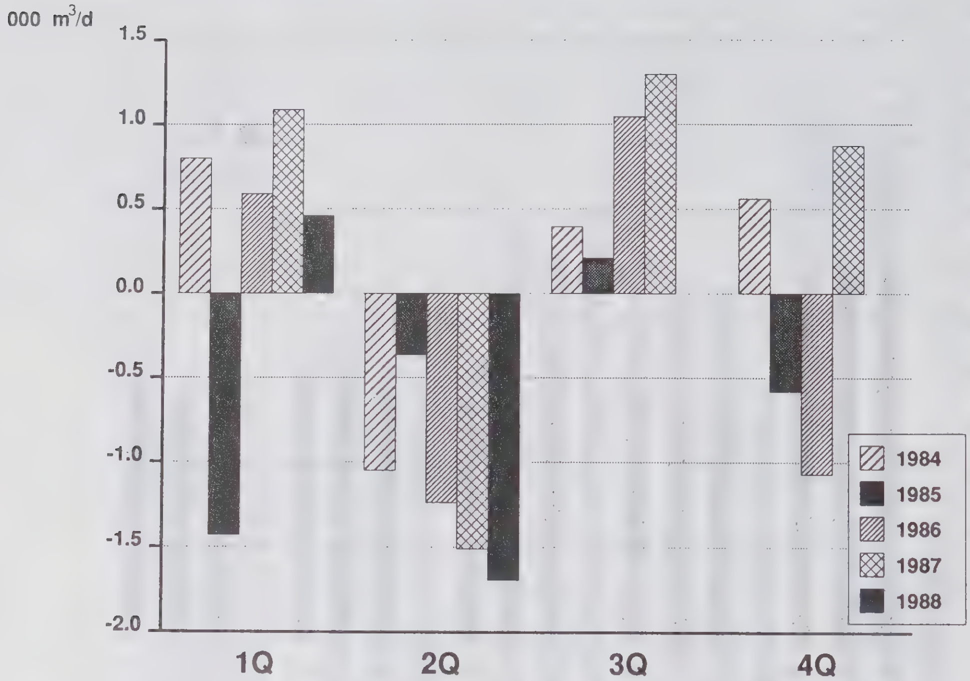
Source: Energy, MInes and Resources

The inventories referred to above do not include crude oil in pipelines or related tankage. If these were included, the ratio of stocks to consumption would increase by about 8 days to 67 days. This level compares with the Organization for Economic Cooperation and Development (OECD) estimated average for the end of the quarter, of 71 days for company stocks. If government stocks were included the average would rise to 100 days.

It is interesting to note that Canadian crude oil and petroleum product stock changes generally follow a traditional seasonal pattern. As illustrated by the following figure, inventories over the last 4 years, despite an absolute total stock level decline, have normally been built during the first and third quarters and drawdown during the second and fourth quarters. The contradictory draw in the first quarter of 1985, to a large extent, reflected refiners' rationalization of inventory levels in anticipation of the introduction of deregulation in June 1985 and the possibility of lower international prices later than year. The fourth quarter of 1987 build, after two consecutive years of draw, can be partially attributed to the reactivation of the Come-by-Chance refinery.

Figure 7.1.4

Crude Oil and Petroleum Product Stock Changes



Source: Statistics Canada

8. Prices

8.1 International Crude Oil Prices

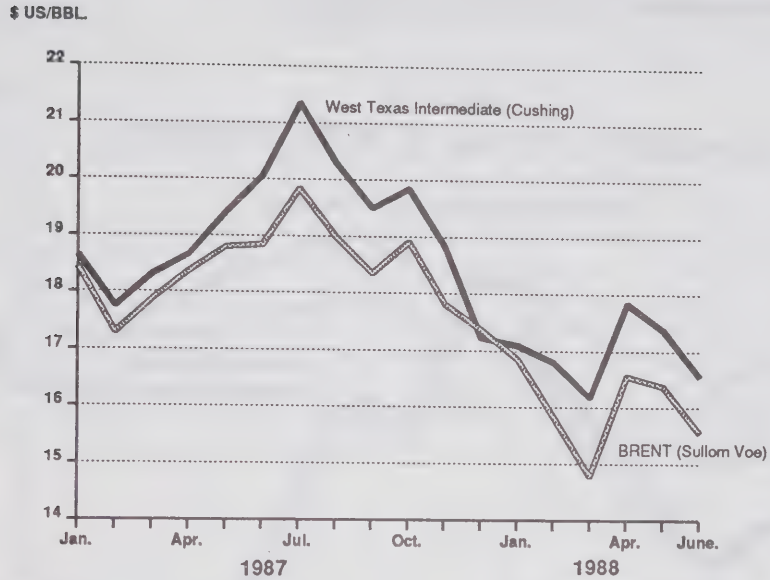
Spot crude oil prices peaked in April after reaching their lowest level of the year in the previous month. Spot West Texas Intermediate (WTI) prices recovered from around $15 per barrel in March to surpass $18 per barrel in April. This firming trend occurred because of a series of meetings between OPEC and, for the first time, a number of non-OPEC producers. The nature of these talks indicated that OPEC and non-OPEC producers were making a concerted effort to stop the erosion of crude oil prices and strengthen world markets. By late April six non-OPEC producers proposed to cut crude oil exports by 5% if OPEC would reciprocate. This was rejected by OPEC which, in turn, could not agree on a counter proposal and the meetings collapsed.

Consequently, spot crude oil prices declined with WTI falling to the low $17 per barrel range and U.K. Brent to around $16 per barrel. Crude oil prices stabilized through May (WTI around $17.50 per barrel) as markets awaited the outcome of the June 11 semi-annual OPEC ministerial conference. This meeting was inconclusive and marked by widespread disagreement, leading to a simple roll-over of the existing accord until year-end (15.06 MMB/D for the 12 signatories, with Iraqi and Neutral Zone production remaining outside the agreement). Ostensibly, the $18 per barrel official selling price benchmark remained an OPEC objective, but the subject was ignored. Crude oil traders turned thumbs-down to this lack of OPEC cohesion and attention turned to the over-supplied market situation.

OPEC was producing in excess of demand requirements (18.5 MMB/D in the second quarter) with no sign that this trend would be reversed. In June, WTI crude averaged $16.55 per barrel and U.K. Brent averaged $15.55 per barrel. By the end of June WTI had fallen to $15.20 per barrel.

Figure 8.1.1

Spot Crude Oil Prices



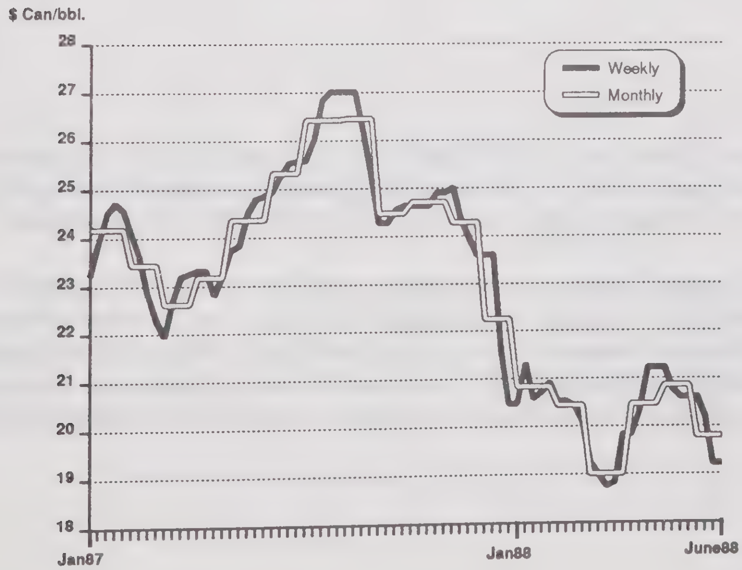
Source: London Oil Report

8.2 Domestic Crude Oil Prices

Light Canadian crude oil prices during the second quarter of 1988 were about $20.38 per barrel, an increase of $0.27 from first-quarter prices. The small increase in crude oil prices can be attributed to two main factors, a world oil price increase of about US$0.75 per barrel which was partially offset by the impact of the strengthening of the Canadian dollar vis-à-vis the American dollar. The change in exchange rates between the first two quarters of 1988 had a downward influence of about $0.60 per barrel on Canadian crude oil prices.

Figure 8.2.1

Edmonton Light Crude Postings
40° API, <0.5% Sulphur

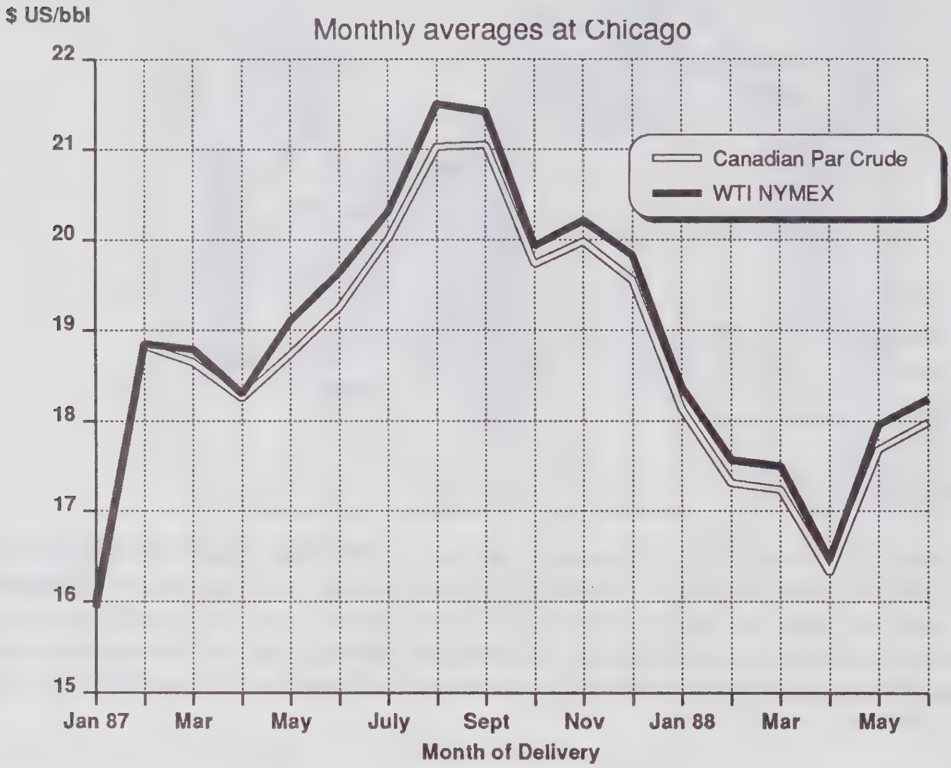


Source: Energy, Mines and Resources

Canadian light crude oil prices follow the trend set by international crudes, primarily the U.S. benchmark crude (WTI). The following figures illustrates the close relationship between prices for WTI and Canadian crudes, after adjustments for delivery times to Chicago.

Figure 8.2.2

Canadian Par Crude vs WTI (NYMEX)



** New York Mercantile Exchange*

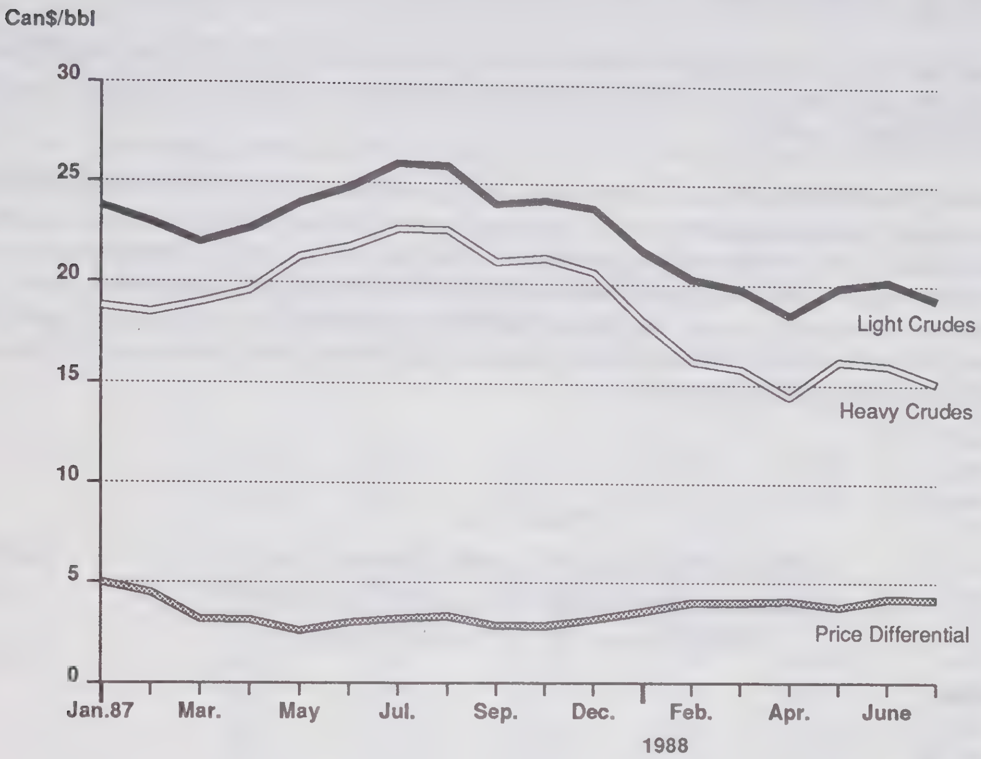
Source: Energy, Mines and Resources

The graph below compares actual prices for Alberta light and heavy crude oil, purchased for use in Canada at main trunk line injection stations. On average, light crude oil quality during the second quarter of 1988 was 37.7° API, 0.39 % sulphur and heavy crude was 24.6° API, 2.41 % sulphur.

The differential between Canadian light and heavy crude prices, for the second quarter, was about $4.00 per barrel, unchanged from the first quarter and about $1.00 more than the level of one year ago. The widening of the price differential between Canadian light and heavy crudes reflects international trends. (For example the price differential between light crude and Wyoming Sour crude increased by US$0.50 per barrel and the price of Mexican Maya crude has softened, compared with light crude prices, by more than $1.00 per barrel.)

Figure 8.2.3

Comparison of Domestic Light and Heavy Crudes
Actual Purchases Price



Source: Energy, Mines and Resources

8.3 Light Crude Values: Export versus Domestic

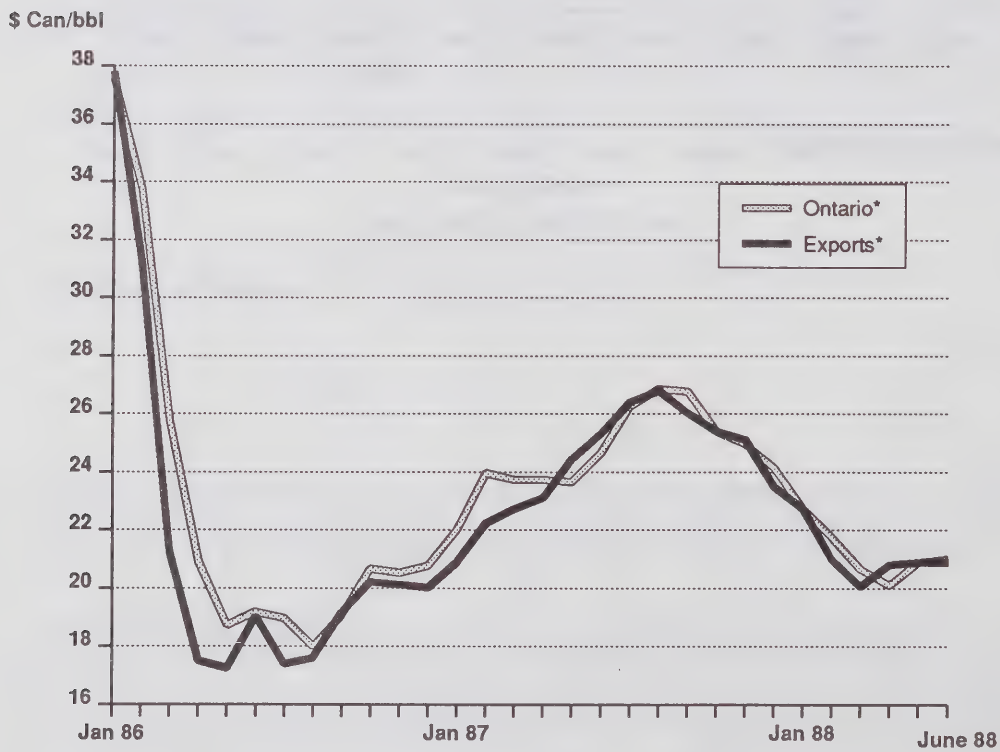
During the second quarter of 1988, the average value of Canadian light crudes exported remained virtually the same as that for similiar crude delivered to Ontario refiners (using Ontario as a proxy for average Canadian refiner acquisition costs of indigeneous light crude and equivalent).

At the end of the first quarter, exported crude could be purchased at $0.60 per barrel less than Canadian crude. Although crude prices increased slightly, this gap narrowed such that by late May the prices were identical at $20.90 per barrel.

Since mid-1987, the difference in value between the two destinations has remained within a narrow range. Prior to this period, price discounting by U.S. refiners was more prevalent in an attempt to offset some of the risk associated with pipeline delivery problems. With the IPL expansion, transportation constraints were less of a concern and the advantage had been removed or narrowed. It should be noted that some gaps may appear from time to time because of differences in delivery times and/or rapid changes in international prices, the effect of which are felt sooner in the United States because of the shorter supply lines and different accounting methods.

Figure 8.3.1

Domestic Light Crude Export and Ontario Domestic Acquisition Values (Adjusted to 38° API, 0.6% sulfur)



** both values adjusted for transportation cost to a common point (Ontario)*

Source: Energy, Mines and Resources

8.4 Petroleum Product Prices

Retail prices of regular unleaded gasoline increased an average of almost 2 cents per litre during the second quarter of 1988. Price increases were recorded in seven of the eleven centres surveyed. In eastern Canada prices increased between 0.2 and 3.4 cents per litre, with the exception of St. John's and Charlottetown, where the prices fell 0.4 and 0.7 cents per litre, respectively. Prices in western Canada continued to be volatile and changes ranged from -3.6 to +5.4 cents per litre.

Retail diesel prices fell an average 0.4 cents per litre during the second quarter, to 47.7 cents per litre. Diesel prices in Calgary and Edmonton were between 5 and 21 cents per litre below those offered in other major Canadian centres.

Average Regular Unleaded Gasoline Prices
Full Serve and Self-Serve
1987-1988

	1987 June	1987 Sept.	1987 Dec.	1988 March	1988 June	% Change Last 12 months
St. John's (Nfld.)	55.8	55.6	55.5	55.2	54.8	-1.8
Charlottetown	53.4	53.3	53.3	53.4	52.7	-1.3
Halifax	49.3	48.9	51.5	50.8	51.0	3.4
Saint John (N.B.)	48.9	48.7	50.7	49.6	50.9	4.1
Montreal	56.9	57.8	57.9	56.9	57.4	0.9
Ottawa	50.8	51.9	51.8	51.4	51.8	2.0
Toronto	47.6	50.6	49.4	46.5	49.9	4.8
Winnipeg	48.0	48.1	47.8	43.9	46.1	-4.0
Regina	42.1	46.6	50.3	48.2	46.7	10.9
Calgary	46.2	44.2	47.2	38.1	43.5	-5.8
Vancouver	50.3	52.8	51.2	48.5	44.9	-10.7
Canadian average	49.9	51.4	51.4	48.4	50.3	0.8
Consumption taxes included:						
Federal	9.05	8.79	8.79	8.86	9.93	9.7
Provincial	9.39	9.43	9.45	9.41	9.82	4.6

Source: Statistics Canada

There were several changes to federal and provincial gasoline and diesel consumption taxes during the second quarter of 1988 (see Appendix II). The federal sales tax was increased 0.07 cents per litre on regular leaded and regular unleaded gasoline, and 0.09 cents per litre on premium unleaded gasoline, while the diesel fuel tax increased only 0.02 cent per litre. The federal excise tax on gasoline increased 1.0 cents per litre on April 1, 1988.

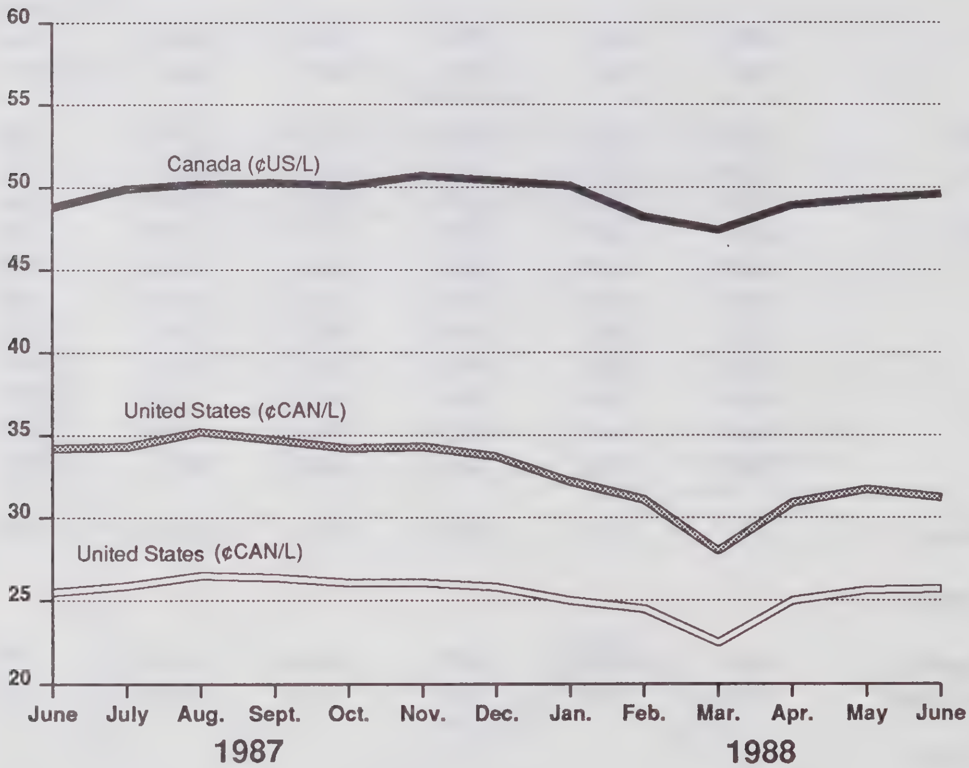
Combined federal taxes on regular unleaded gasoline in June of 1988 accounted for 19.7% of the pump price, as compared with 18.3% in March. The federal sales tax on gasoline is based on a 12% ad valorem rate and is adjusted quarterly to reflect changes in a twelve-month average industrial product price index for gasoline, with a one-quarter lag.

Three of the provinces and the Northwest Territories, all with ad valorem tax rates, made minor adjustments to their taxes. The tax changes in Ontario and British Columbia were announced in their annual budget. In Ontario, the gasoline tax increased 1 cent per litre and a 3 cent per litre surcharge was placed on leaded gasoline. In British Columbia an increase in the ad valorem tax rate will affect the July taxes. The transit tax in Vancouver was increased as well.

The following figures compare average gasoline prices in Canada and the United States. The average pump price in Canada and the United States increased 2.2 and 3.2 cents per litre, respectively, during the second quarter of 1988. The U.S. price would have been almost 1 cent per litre higher had the Canadian dollar not strengthened during the quarter.

Figure 8.4.1

Average Retail Price of Motor Gasoline
Canada vs United States
(Average Full-Serve and Self-Serve)

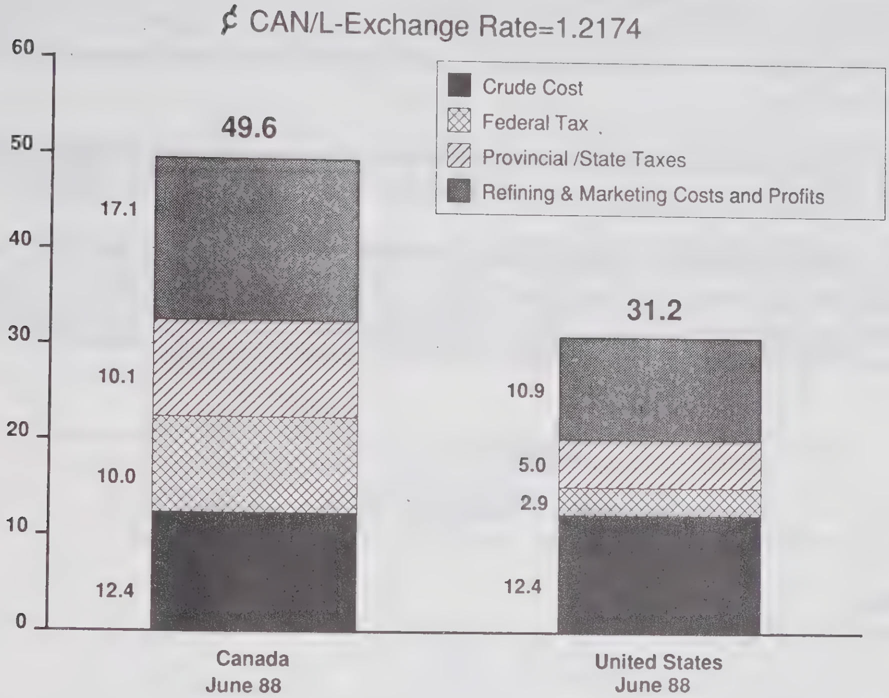


Source: Energy, Mines and Resources

The bar charts illustrate the components of the average pump price in each country using June of 1988 data. Crude costs are the average refinery acquisition cost (cost of crude received at the refinery gate) lagged by 60 days in Canada and 45 days in the United States. The refining and marketing costs and profits component is the residual revenue available to cover refining, marketing and distribution costs and to provide a return to the industry on its investment.

Figure 8.4.2

Breakdown of Average Pump Price
Canada and United States



Source: Energy, Mines and Resources

Gasoline prices in Canada in June of 1988 were 18.4 cents per litre higher than in the United States. This reflects a narrowing in the differential during the last quarter of 1.0 cent per litre. About two-thirds of the differential in June was accounted for by higher taxes in Canada (12.2 cents per litre). The balance is attributable to higher refining and marketing costs and profits in Canada. The larger refining and marketing costs and profits component in Canada results from structural differences between the two markets e.g. economies of scale in the form of substantially higher volume per unit of investment favour U.S. refiners and marketers.

9. Drilling Rig Activity

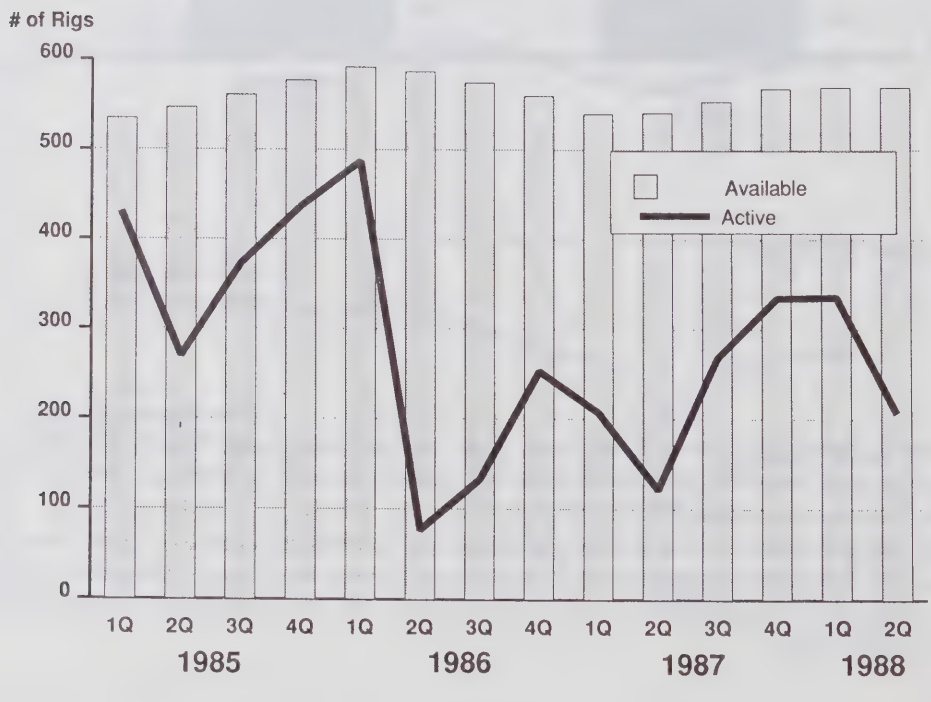
With an average rig utilization rate of 36%, drilling rig activity in the second quarter of 1988, compared with the same period in previous years, was the most active since 1985, when utilization was 49%. The second quarter activity was 13 percentage points higher than a year earlier and 26 percentage points better than in 1986, when drilling virtually ceased following the crude oil price collapse. In 1988, drilling rigs were able to return to field sites earlier in the quarter, since spring thaw, with the resulting road bans, ended sooner than normal.

During the first half of the year, the number of available drilling rigs was 570, 5%, or 30 rigs more than in 1987. Even with this additional capacity, rig utilization was almost a fifth higher in 1988, at 47%.

The higher drilling activity is partly a result of continued incentives and royalty holidays that have the effect of reducing net drilling costs. Producers are trying to take advantage of the existing programs since the federal incentives are scheduled to be reduced at the beginning of October 1988, coincidental with a reduction in the provincial royalty holiday, which will fall from three to one year.

Figure 9.1.1

Drilling Rig Activity



Source: Energy, Mines and Resources

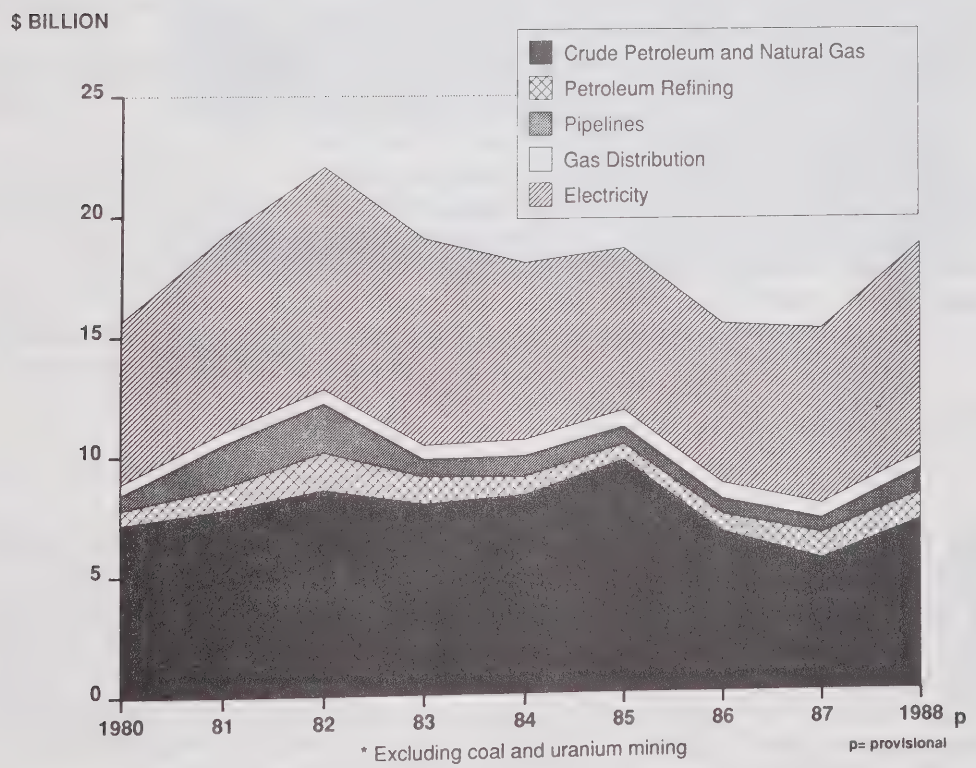
10. Capital Expenditures in the Petroleum Industry

10.1 Capital and Major Repair Expenditures

Based upon a mid-year survey of capital expenditure intentions*, the upstream petroleum industry still intends to spend about $7,100 million in 1988 on capital and major repair expenditures. This spending level is down only marginally ($200 million) from the level forecast by the industry at the end of last year, despite the weakness in oil prices experienced during the first half of 1988. The increase over 1987 capital expenditures of $1,600 million (almost 30%) may appear quite remarkable given the current price forecast uncertainty but it still falls short of a return to the level of expenditures undertaken by the industry in the first half of the decade. Nevertheless, much of the expenditure increase represents projects. Some of the drilling activity has been encouraged by a combination of federal and provincial incentives, many of which are due to expire or to be reduced in the latter half of the year. It should be noted that capital expenditures in upstream natural gas related activities are included in these numbers and have contributed to the 1988 surge in spending. It is also noteworthy that drilling activities were on the rise in all four western provinces.

Figure 10.1.1

Total Energy Capital Expenditures *

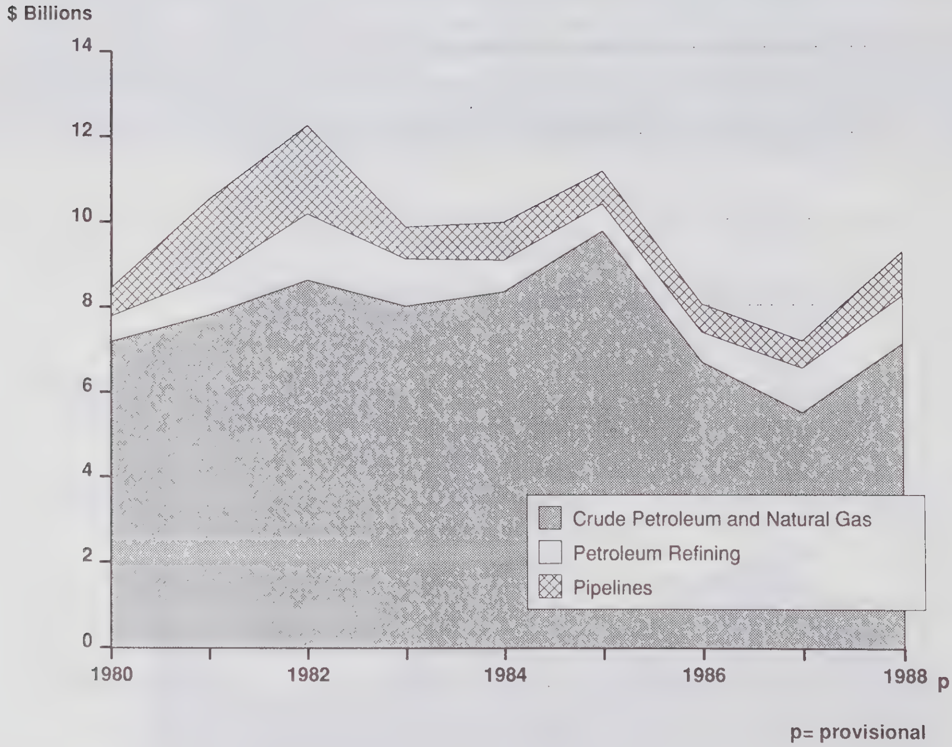


** Source: Statistics Canada, cat. no. 61-206.*

Capital expenditures in the petroleum refining industry are expected to exceed $1,100 million, up almost 8% from 1987. This level of expenditures is unchanged from the end-1987 forecast. The increase of $80 million from 1987 is distributed across all regions of the country and reflects in part the investments underway in the Canadian refining industry to meet anticipated environmental restrictions as well as higher product specifications for certain uses of petroleum products.

Figure 10.1.2

Capital Expenditures in the Petroleum Industry



Source: Statistics Canada

The pipeline industry expects to spend over $1 000 million as well in 1988, a sharp increase of over 60% from 1987. This increase is also up sharply from the end-1987 forecast for 1988, which was about 40% over the prior year. Interprovincial Pipe Line completed Phase III of its expansion and 'debottlenecking' program late in 1987 but has nevertheless continued to operate at full capacity during the first half of 1988. The company is actively studying another major expansion to its system which could cost about $1,000 million. Trans Mountain Pipe Line is also evaluating a possible major expansion project which would permit higher exports to Pacific markets. It should be noted that some of the growth in pipeline related capital expenditures is tied to expansions of gas lines for expanded export markets.

Overall petroleum related capital expenditures are planned to exceed $9,200 million in 1988, a 29% increase over 1987. By comparison, energy related capital expenditures are expected to rise by almost 24% to $18,800 million or roughly 12% of capital expenditures in the entire economy, which are also expected to rise by roughly 12% over 1987. As a result, the relative importance of the energy sector in the overall economy will continue to grow and make a significant contribution to total output.

10.2 Pipeline Transportation

In May, reflecting a trend to more optimistic crude oil supply forecasts, the two major oil pipeline companies in Canada, the Interprovincial Pipe Line Company (IPL), a division of Interhome Energy Inc., and Trans Mountain Pipe Line (TMPL), both announced tentative plans for major expansions, at estimated costs of $1.1 billion and $500 million, respectively. Each company would add about 30 000 m^3/d of additional capacity by the early 1990s, by looping and/or adding additional lines.

Interprovincial Pipe Line Expansion

In late 1984 and early 1985 it became evident to the oil industry that light crude productive capacity was not falling as quickly as expected whereas heavy crude oil production was increasing faster than expected. As a result IPL began a three-phased expansion to accommodate the forecast increase in transportation capacity requirements.

The first phase, at a cost of $20 million was completed in the fall of 1985 and increased pipeline capacity by 12 000 m^3/d. The second phase, finished early in 1987 ($90 million) increased capacity by another 25 000 m^3/d, and involved installing new pumping equipment and line modifications. The final phase of the expansion was completed late in 1987, adding 15 000 m^3/d, at a cost of $245 million. (It should be noted that incremental capacity cannot be added directly to previous capacity to estimate current capacity. The crude mix has been getting heavier, leading to an erosion of volumetric capacity. These additions essentially offset some of the volumetric loss.)

A further $25 million expansion, scheduled for completion in mid-1988, will add another 10 000 m^3/d of capacity.

Despite these expansions, IPL is once again short of pipeline capacity, reflecting higher-than-expected production of both Alberta conventional light crude oil and heavy crude oil. According to IPL officials, the IPL system will probably be short of capacity, by about 4 000 m^3/d to 8 000 m^3/d, on an ongoing basis through much of 1988 and 1989. Since late 1987, IPL has found it necessary to apportion available space on the line as shippers have consistently tendered for more space than available. The apportionment system in place has certain inequities which would be eliminated with excess capacity on the system but at a cost to all shippers.

Long Term Forecast

IPL has compiled oil supply forecasts under three (low, base, high) crude price options as of January 1988, based on discussions with industry in late 1987, with modifications to include the January Alberta Energy Resource Conversation Board (AERCB) revised medium-term light crude supply forecast. According to the base case forecast, (1987 US$20 per barrel in 1988 to $29 per barrel by 1995), there will be a continued capacity shortfall throughout 1988 and 1989, which should begin to lessen by 1990 and could disappear between 1991 and 1994. However, assuming forecast production increases, by 1994 capacity shortfalls will likely develop, reaching up to 50 000 m^3/d.

IPL is somewhat skeptical about the forecasts for the short to medium term. Light crude production has not yet lived up to the pessimistic projected decline. Successive AERCB forecasts throughout the 1980s illustrated a much more gradual decline than had been anticipated. Other factors (individual refinery demands, timing of upgraders, use of an expanded TMPL for heavy crude exports, bitumen projects) all add to the uncertainty. The dilemma is that most forecasts do not support a pipeline expansion before the mid 1990s. However, history has shown that capacity requirements are usually greater than forecast. IPL needs a good forecast of demands 2 to 3 years in the future to plan pipeline investment. If there is no 1990 shortfall, they should not build capacity.

Current Situation

IPL considers that opportunities to gradually expand capacity no longer remain. The next increment of capacity involves a new line from Edmonton to Superior (except for a few idle sections at present) and extensive looping from Superior to Chicago at an estimated cost of about $1.1 billion for about 30 000 m^3/d of additional capacity.

IPL has reviewed their findings with some of the larger producers, shippers and industry associations. Although initial feedback is cautiously supportive, a committee, composed of the AERCB, Canadian Petroleum Association (CPA) and Independent Petroleum Association of Canada (IPAC) is now updating future oil supply projections. The committee should decide by the early fall whether or not to support the IPL proposal.

Given the risks and significant costs involved, the industry must study the proposal very carefully. (The new/looped line will have a design capacity of 30 000 m^3/d and the incremental tariff to Sarnia would be about $0.35 per barrel if the capacity is used, a 30% increase over the current tariff of about $1.20 per barrel.) If the additional capacity is not utilized, the incremental tariff would be about $0.55 per barrel, a 50% increase.

Trans Mountain Pipe Line

With continued growth in heavy crude production, producers have sought market expansion and diversification. As a result, exports of heavy crude through the Trans Mountain system both to the United States and Far East destinations have jumped from nil in the first quarter of 1986 to almost 4 000 m^3/d in the first quarter of 1988, representing about 15% of pipeline capacity. (Like IPL, Trans Mountain has been operating at close to capacity levels (28-30 000 m3/d) throughout most of 1988.) Because of the forecast increase in heavy crude production and exports, in the fall of 1987, Trans Mountain pipeline applied to the National Energy Board for a two-staged expansion of its system from Edmonton to Vancouver.

Stage one of the expansion, which is required to accommodate the export of 6 000 m^3/d of blended bitumen in 1990, (an increase of 4 000 m^3/d from 1987), would be completed by late 1989 at a cost of $52 million. The new facilities would include additional tankage at Edmonton and Vancouver (to segregate light and heavy crude), two new pump stations and modifications to existing pump stations, however actual pipeline capacity will only increase slightly. The need for the stage two expansion, at a cost of $27 million was less definite, but was based on forecast movements of methanol and methyl tertiary butyl ether (MTBE) by 1990. In August the Board approved the stage one expansion, but it did not approve the proposed second stage expansion, because additional terminaling facilities, which were not requested in this application, would be required.

However, even before a final decision was made on the first two stages, TMPL announced plans for a further major expansion.

TMPL is proposing a gradual $500 or $600 million expansion which would eventually see the capacity of the system doubled, to 60 000 m^3/d (including the stage one expansion) by gradually looping and adding additional facilities along the system.

Although the two major expansion proposals could be in competition, each is primarily based on continued strong growth in heavy crude supply in the future. Some analysts feel the Pacific Rim countries, which are rapidly developing and depend upon heavy crude, offer much greater market potential than the eastern and midwest U.S. To expand Canadian heavy markets further south and east of the U.S. midwest may affect U.S. IPL - connected markets via marginal pricing impacts, thereby lowering producer netbacks on all sales. On the other hand, western oil producers have preferred to ship to the U.S. midwest market. U.S. west coast market prices have been depressed by the Alaska North Slope (ANS) crude export ban, while Pacific Rim markets suffer from higher transportation costs and Persian Gulf competition. In addition, some producers believe that the U.S. midwest is capable of absorbing considerably more Canadian crude, particularly if additional upgrading capacity is added to U.S. refineries.

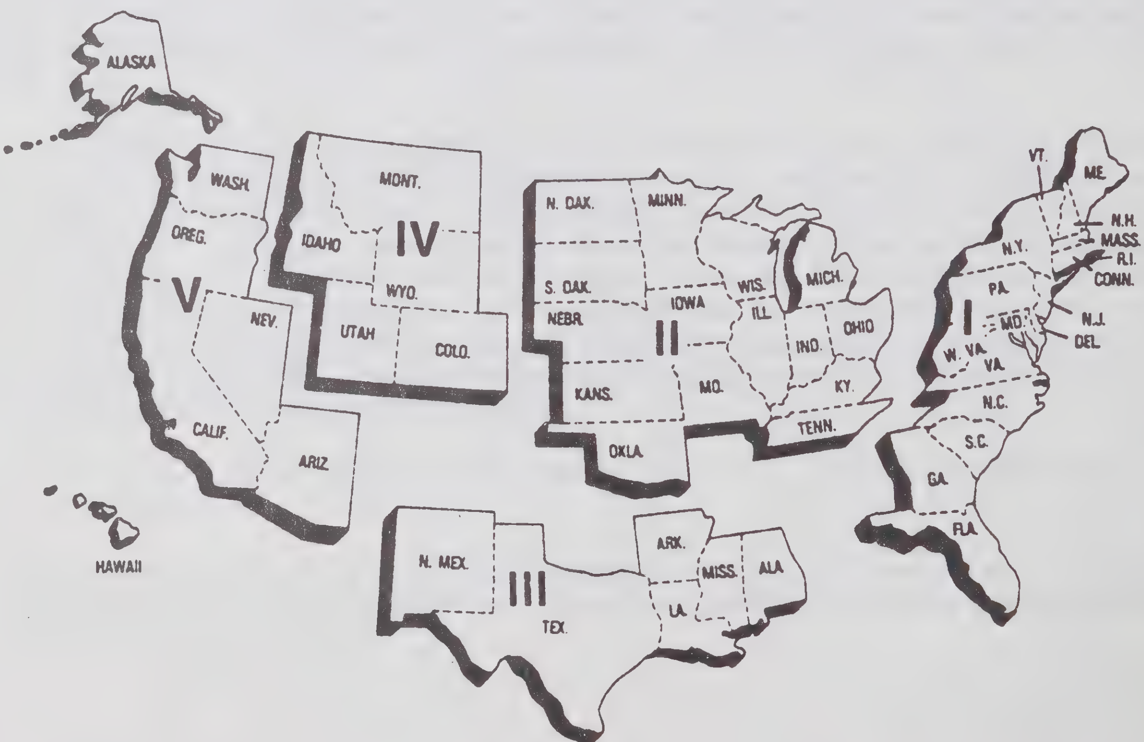
A consensus has not yet developed in the upstream oil industry with respect to the need for these expansions, either now, or in the next five or six years. Much depends on industry confidence in the crude oil supply forecasts.

Moreover it appears that the industry would like to review other options to large scale pipeline expansions. Various industry groups are developing and reviewing alternatives which, depending on supply scenarios, could singularly, or in combination, alleviate crude oil transportation problems without relying on major risky pipeline expansions.

APPENDIX I
Light and Heavy Crude Exports by Destination

(June 1988 is provisional)

Destinations	Light			Heavy		
	1986	1987	1988	1986	1987	1988
	000 m^3/d					
United States						
PADD I	8.6	7.7	6.4	2.2	2.7	2.6
PADD II	26.1	32.5	33.9	43.1	48.4	53.4
PADD III	4.0	0.0	0.0	1.0	0.8	2.4
PADD IV	6.0	7.4	7.2	4.2	3.5	3.6
PADD V	5.2	2.3	2.8	0.0	0.2	1.2
Total U.S.	49.9	49.9	50.3	50.5	55.6	63.2
Offshore	0.0	0.9	2.0	0.0	0.0	2.4
Total Exports	49.9	50.8	52.3	50.5	55.6	65.6



Source: Energy, Mines et Resources

APPENDIX II
Consumption Taxes on Petroleum Products
June 1, 1988

	Ad valorem		Gasoline			
	Mogas	Diesel	Reg L	Reg UL	Prem UL.	Diesel
				(cents per litre)		
FEDERAL TAXES						
Sales			3.43*	3.43*	3.53*	2.65*
Excise			6.5*	6.5*	6.5*	4.0
PROVINCIAL TAXES						
Newfoundland	22	26	9.8	9.8	9.8	12.1
Prince Edward Island	20	23	8.7*	8.7*	8.7*	9.1
Nova Scotia	20	21	8.6*	8.6*	8.6*	9.0
New Brunswick	20	23	7.8	8.2*	8.6*	8.0
Quebec (a)			14.4	14.4	14.4	12.45
Ontario			12.3*	9.3*	9.3*	9.9
Manitoba			8.9	8.0	8.0	9.9
Saskatchewan		-	7.0	7.0	7.0	7.0
Alberta			5.0	5.0	5.0	5.0
British Columbia	22.5*(b)	22.5*(b)	9.35*	7.35*	7.35*	7.79*
Yukon	-	-	4.2	4.2	4.2	5.2
Northwest Territories	17	(c)	8.4*	8.4*	8.4*	7.1*

(a) Reduced by varying amounts in certain remote areas and within 20 kilometers of the provincial and U.S. borders

(b) Additional transit tax of 3.0* cents per litre in Vancouver.

(c) 85% of gasoline tax.

** Changed since last quarter.*

Source: Energy, Mines and Resources

Glossary

Bitumen	A naturally occurring viscous mixture composed mainly of hydrocarbons heavier than pentane, which may contain sulphur compounds and which in its natural state is not recoverable at a commercial rate through a well.
Conventional areas	Those areas of Canada that have a long history of hydrocarbon production. Conventional areas are also referred to as nonfrontier areas.
Crude oil and equivalent	Includes crude oil, synthetic crude, oil produced from oil sands plants, and condensate.
Feedstock	Raw material supplied to a refinery or petrochemical plant.
Heavy crude oil	Loosely applied, crude oils with a low API gravity (high density).
In situ recovery	With reference to oil sands deposits, the use of techniques to recover bitumen without the necessity of mining the sands.
Light crude oil	Crude oil with a high API gravity (low density). Generally includes all crude oil and equivalent hydrocarbons not included under heavy crude oil.
Natural gas liquids	Those hydrocarbon components recovered from raw natural gas as liquids by processing through extraction plants, or recovered from field separators, scrubbers or other gathering facilities. Includes the hydrocarbon components ethane, propane, butane and pentanes plus, or a combination thereof.
Oil sands	Deposits of sands and other rock aggregate that contain bitumen.
Pentanes plus	Also referred to as condensate. A volatile bydrocarbon liquid composed primarily of pentanes and heavier hydrocarbons. Generally a by-product obtained from the production and processing of natural gas.
Productive capacity	The estimated production level that could be achieved, unrestricted by demand, but restricted by reservoir performance, well density and well capacity, oil sands mining capacity, field processing and pipeline capacity.
Shut-in capacity	The unused productive capacity of currently producing oil and gas wells plus the total production capability of all shut-in oil and gas wells, whether or not they are connected to surface gathering and production facilities.
Synthetic crude oil	Crude oil produced through treatment of oil sands in upgrading facilities designed to reduce the viscosity and sulphur content.

Energy, Mines and Resources Canada
Énergie, Mines et Ressources Canada

The Canadian Oil Market

Vol. IV, No. 3, Third Quarter 1988

Canada

THE CANADIAN OIL MARKET

Vol. IV, No. 3, Third Quarter 1988

Domestic Oil Division
Energy Sector
Energy, Mines and Resources Canada

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Table of Contents

Table of Figures

List of Tables

THE CANADIAN OIL MARKET

OVERVIEW

- *A review of heavy fuel oil consumption trends over the last five years indicates that after half a decade of substantial declines, heavy fuel demand has grown at an annual rate of about 10% since 1985 - in response to lower prices, high demand for oil-fired electricity generation and strong industrial activity. Almost two-thirds of this growth has occurred in the Atlantic region , (pg.6).*

- *After significant increases in both light and heavy crude supply in 1987, growth in capacity has stalled in 1988. Alberta conventional light crude capacity is once again on a declining trend, after a one-time upward spike in the last half of 1987. In part because of lower prices, heavy crude supply has basically remained flat since the fourth quarter of 1987, (pg12).*

Oil Supply/Demand Balance
(Third Quarter)

	1987	1988
	(000 m^3/d)	
Production	266	274
Consumption	237	239
Net Exports	29	35

- *On a year-over-year basis both exports and imports were up in the third quarter of 1988 - but only marginally in the case of light crude exports, (pg19).*

- *On a year-over-year basis, production of heavy crude and synthetic increased, while light crude declined marginally, reflecting some pipeline constraints, (pg13).*

OUTLOOK

- *During the third quarter three major long term oil projects (all involving government participation) were announced: Hibernia, the Lloydminster heavy oil upgrader and the OSLO oil sands plant. All are scheduled to begin operation in the early to mid-1990s, (pg17).*

- *According to a short-term forecast prepared by the National Energy Board (NEB), Alberta conventional light supply and raw heavy crude capacity are expected to decline in 1989 , (pg16).*

- *Two major long-term forecasts were schedued to be published in December 1988 - one by the NEB, the other by the Alberta Energy Resources Conservation Board. A review of these forecasts will be included in the future editions of the 'Canadian Oil Market', along with the potential impact on proposed pipeline expansions (see Second Quarter 1988 edition).*

1. Domestic Demand

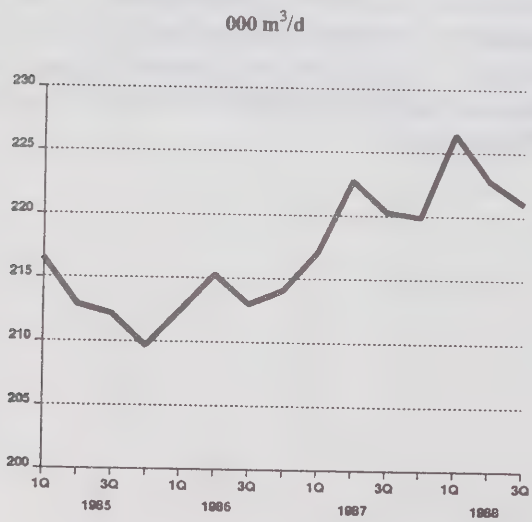
1.1 Seasonally Adjusted

- *Consumption fell by 1% in the third quarter from the previous quarter, but was still up from 1987 by a little over 1%.*

- *Across the products, only heavy fuel oil showed an appreciable jump in consumption, reflecting some interfuel substitution back to oil.*

Seasonally-adjusted oil product consumption in Canada during the third quarter of 1988 averaged 221 000 m^3/d, a decrease of 1% from the previous quarter, and over 2% from the first quarter of 1988. The two consecutive quarterly consumption declines after the spike upwards in consumption in the first quarter appear to be in part attributable to inventory shifts by end-consumers and distributors. They built up inventories in March, particularly motor gasoline and diesel fuel, in order to capitalize on a federal tax increase of one cent per litre, effective 1 April, 1988. Statistically, this behaviour explains part of the 4% jump in total sales in the first quarter. The subsequent decline in sales during the second quarter reflects the "run-down" of the inventories accumulated prior to the tax increase. During the third quarter, decumulation of inventories occurred in anticipation of price declines for refined products following upon crude price declines. After adjusting for these inventory swings, the trend growth rate in consumption of roughly 2% was maintained

Figure 1.1.1
Total Petroleum Product Consumption
(Seasonally-Adjusted)



In comparison with the first half, all products recorded declines with the exception of heavy fuel oil which increased by 7% to 21 000 m^3/d, reflecting increased demand for generation of electricity in the Atlantic region, and some switching back to heavy fuel oil from gas and electricity in central Canada.

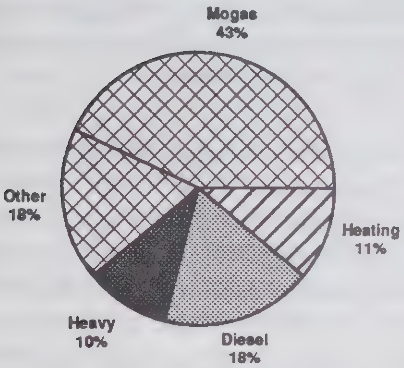
Most of the decline occurred in transportation fuel use, down 4% to 134 000 m^3/d, with motor gasoline accounting for 80% of the decline. This represents the lowest level of motor gasoline consumption since 1985. (Motor gasoline consumption changes have been in the plus or minus 1% range over the past five years.) Despite a drop of 2%, diesel demand remained substantially higher than previous years. This growth reflects the strong performance of the Canadian economy, particularly in the industrial and commercial sectors with the consequent strong demand from the truck transportation sector.

Heating oil consumption continues to fall, down 6% to 19 500 m^3/d. In contrast to the second quarter when consumption of "other products" rose by 9%, there was a third-quarter decline of 3%.

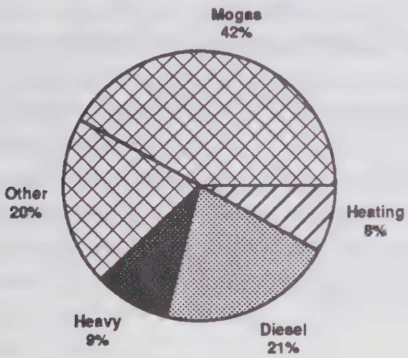
Figure 1.1.2 illustrates the change in the components of total oil product sales between 1983 and 1988. Transportation fuel now accounts for 63% of total oil product consumption, up two percentage points since 1983. Despite the strong economic growth over the past two years, the motor gasoline share fell by 1 percentage point to 42%, reflecting greater fuel efficiency and relatively high prices, in part caused by higher provincial and federal taxes. In contrast, growth in diesel fuel refinery production has mirrored economic growth, with a 17% increase in market share to 21 %.

Figure 1.1.2
Canadian Oil Product Sales
(First Nine Months)

1987



1988

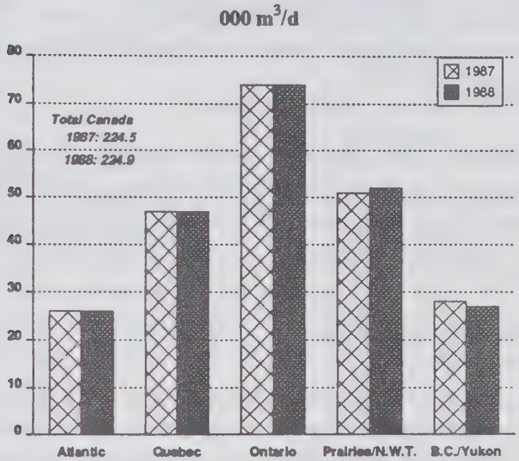


Heating oil consumption continues to decline and now constitutes only 8% of total product sales. While heavy fuel oil also represents less than 10% of total sales, there has been strong growth over the last two years, mainly because of increased demand for oil-fired electricity generation in the Atlantic region and more recently, some substitution from gas and electricity in the industrial sector in central Canada. (Section 1.5 provides a more detailed review of the heavy fuel oil sales trend) ."Other products" gained 2 percentage points to 20%. Several products, particularly those related to the petrochemical industry, recorded strong increases in recent years.

1.2 Regional Consumption

Oil product demand (unadjusted) in Canada during the first nine months of 1988 rose by 2%; however, during the third quarter it lost much of its momentum, recording a marginal increase of 0.2%, to 225 000 m^3/d.

Figure 1.2.1
Regional Petroleum Product Consumption
(Third Quarter)



Despite the drought, the Prairies recorded the largest regional demand increase, up 2% to 52 000 m^3/d, reflecting the strong demand for transportation fuels, particularly diesel fuel. Consumption at both ends of the country fell: by 1% to 26 000 m^3/d in the Atlantic region, and by more than 3% to 27 000 m^3/d in British Columbia.

Table 1.2.1
Transportation Fuels
(% Change - Third Quarter 88/87)

	Atl.	Que.	Ont.	Pra.	B.C.	Can.
Gasoline	1.6	3.0	(1.2)	1.7	(1.7)	0.5
Diesel	10.2	10.3	(4.2)	5.5	6.6	4.4
Total	**4.6**	**5.1**	**(1.9)**	**3.2**	**1.6**	**1.7**

Demand for transportation fuels (excluding aviation turbo fuel) continued to climb, with an increase of over 3% during the first nine months, and 1.7% over the third quarter. With the exception of Ontario, down 2%, all other regions recorded increases ranging from less than 2% in British Columbia to 5% in Quebec. The decline in Ontario may have reflected a pause in the relatively strong growth in this region over the last few years, and some end-consumer inventory drawdown. In line with recent trends, diesel fuel has been the main contributor to the transportation fuel increase.

The economic growth in the Atlantic region was somewhat late in occurring in comparison with the other regions of the country; however, good performances have been recorded over the past two years. This growth was reflected in high demand for transportation fuels.

In Quebec, strong demand in the forestry and mining industries contributed to a 10% increase in diesel fuel consumption, with demand for motor gasoline up by 3% to yield an overall growth rate of 5%.

Despite the drought in the Prairies, transportation fuel consumption rose by 3.2%, with diesel fuel up by 5.5%. Part of this increase reflected higher drilling activity stimulated by an approaching deadline (September 30, 1988) after which a reduction in grants under the federal Exploration and Development Incentive Program would come into effect (See section 9).

Table 1.2.2
Non-Transportation Products
(% Change - Third quarter 1988/87)

	Atl.	Que.	Ont.	Pra.	B.C.	Can.
Light Oil	5.5	(11.8)	2.8	(9.7)	(32.1)	(5.6)
Heavy Oil	(11.2)	10.1	8.9	22.5	16.1	2.6
"Other products"	(3.2)	(12.7)	5.3	(1.2)	(22.4)	(3.9)
Total	**(6.0)**	**(7.8)**	**5.9**	**(1.5)**	**(14.3)**	**(2.7)**

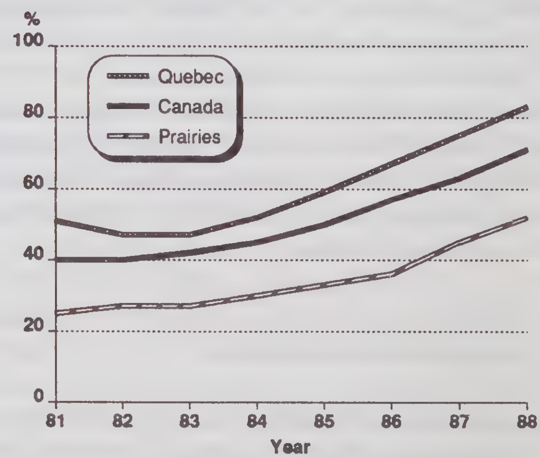
In contrast to transportation fuels, demand for non-transportation products declined in all regions of the country, except in Ontario. Led by a strong increase in heavy fuel, up 9%, non-transportation demand in Ontario rose 6%, possibly reflecting some inventory building. The largest drop was in British Columbia at more than 14%.

1.3 Unleaded Motor Gasoline Sales

During the first three quarters of 1988, unleaded gasoline (regular and premium) represented around 71% of total gasoline sold in Canada, an improvement of about 8 percentage points from a year ago and over 30 points from the 1981 level.

In 1988, all regions recorded substantial increases in unleaded gasoline use, (in the range of 7 to 8%). As indicated in Figure 1.3.1, this trend has been accentuated over the past two years. Society is more aware of the health and environmental hazards of leaded fuel emissions and most new cars require the use of unleaded fuel. As well, some provincial governments have increased taxes on leaded fuel to equalize the price of regular unleaded and leaded fuel, thereby eliminating an incentive to use leaded gasoline. In addition, because of increased environmental concerns, the federal government has recently announced that after December 1, 1990, leaded gasoline for automobile use will no longer be sold in Canada. This decision reduces, by two years, the time frame during which refiners must adjust their production of gasoline in order to comply with the new rules.

Figure 1.3.1
Unleaded Gasoline Market Share



While unleaded gasoline now accounts for over 70% of gasoline sales on a national basis, there are significant regional differences. In eastern Canada (including Ontario) unleaded market share is near 80%. Quebec is currently the region where the share of unleaded gasoline is the largest, accounting for 83% of total motor gasoline consumption. On the other hand, unleaded gasoline consumption in the Prairies accounts for only 52% of total motor gasoline consumption, the lowest share in the country. This difference reflects, to a certain extent, the large agricultural sector which still operates some of its equipment with leaded gasoline. Another important factor is the slower rate at which the automobile fleet is replaced in the Prairies.

1.4 International Oil Consumption

In the first nine months of 1988 compared with the same period in 1987 Canada's growth in consumption of petroleum products was virtually identical to the United States, with an increase of around 2%. The growth in both Canada and the United States was mainly attributable to strong increases in transportation fuel use, reflecting the strong performance of the North American economy.

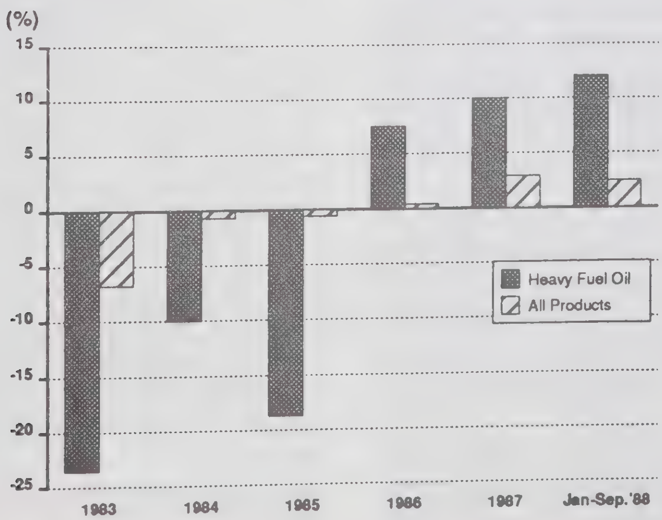
Table 1.4.1
Petroleum Product Consumption
(First nine months 1988/87)

			OECD	
	Canada	U.S.	Europe	Pacific
		% Change		
Product				
Motor Gasoline	1.0	2.0	2.6	2.5
Middle Distillate	6.7	3.6	(4.0)	9.1
Heavy Fuel Oil	11.5	(0.8)	(8.0)	2.1
Other Products	(4.4)	0.8	1.6	14.8
Total	2.2	2.1	(1.2)	5.2

In Europe, oil consumption fell by 1.2% as a result of large reductions in heating oil and heavy fuel oil consumption. The drop in heating oil demand reflects relatively high consumer stocks following the mild weather of last winter. Despite this drop in overall consumption, transportation fuels remained strong, as in most industrialized countries.

In the Pacific Rim region all product categories registered increases as a result of strong economic growth, particularly in Japan.

Figure 1.5.1
Heavy Fuel Oil and All Product Consumption
(% Change)



1.5 Heavy Fuel Oil Consumption Trends

Since bottoming out in 1985, petroleum product consumption in Canada has increased at an annual growth rate of 1.5%. Much of the increase reflected lower oil prices and the strong performance of the Canadian economy. With respect to individual products, as outlined in Figure 1.5.1, the largest growth has been in demand for heavy fuel oil. Which has recorded an annual growth rate of 10% since 1985.

The turnaround in heavy fuel oil consumption was in sharp contrast to the first half of the 1980s. During that period, heavy fuel oil demand declined sharply reflecting consumer conservation (high prices and government "off-oil" incentives), and fuel substitution (natural gas and electricity). By 1985, domestic heavy fuel oil sales had fallen to 16 000 m^3/d or 8% of total product sales, compared with 41 000 m^3/d or a 15% share in 1980. Oil prices fell dramatically in 1986, however, and heavy fuel oil once again became competitive. Because of this decline, heavy fuel oil consumption surged 8% in 1986, 10% in 1987, and 12% in the first nine months of 1988.

The following two sections review the sectoral and regional trends in heavy fuel oil demand over the last 3 to 4 years.

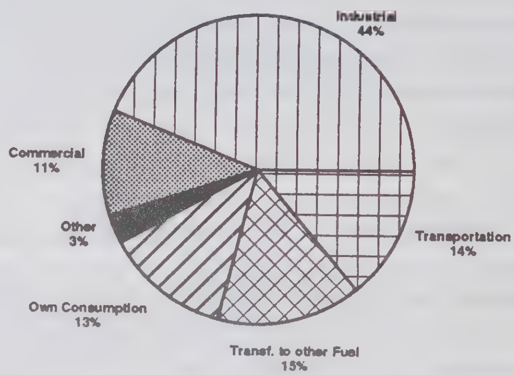
Sectoral Review

Heavy fuel oil demand by sector has shifted considerably since 1983. In 1983, heavy fuel oil used to generate electricity represented only 15% of total sales. By 1985 this component had risen to almost 22%, as demand increased slightly despite the decline in total sales. By 1987 more than a quarter of heavy fuel oil consumed was for electricity generation, with virtually all of this in the Atlantic region (which accounts for more than 95% of Canadian demand in this sector). The largest increase was in 1987 when there was a 60% jump in the Atlantic. As mentioned in previous reports this increase was related to low water levels which reduced hydro-electric generation.

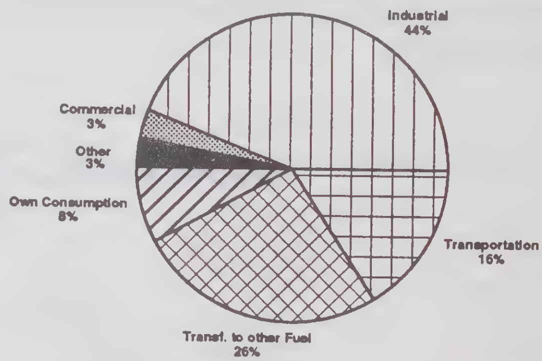
There has also been strong growth in the transportation sector since 1985, largely in marine demand in the Atlantic region and British Columbia. After declining by more than a third between 1983 and 1985, demand grew by about 25% from 1985 to 1987. The transportation sector accounted for 16% of heavy fuel consumption in 1987, compared with 14% in 1983.

Figure 1.5.2
Heavy Fuel Oil Demand by Sector

1983



1987



Despite low prices in 1986, demand in the commercial sector has continued to decline since 1983, at an annual rate of 32%, and in 1987, constituted only 2% of heavy fuel oil sales compared with 11% in 1983. All regions recorded substantial declines, but it was most evident in Quebec (which accounted for 40% of heavy fuel oil use in this sector in 1987). Substitution to other sources of energy was the main reason for the decline, particularly in Quebec where conservation and government "off-oil" incentives also played an important role.

Despite an increase of 8% in crude run to still since 1983, refineries' own consumption has recorded a drop of almost 50%. This decline is related to a number of factors, including the increased use of other fuels (mainly natural gas), a decline in the number of refineries and higher refinery efficiency.

The industrial sector still accounts for the largest share of heavy fuel oil consumption. Except in 1985, when it accounted for almost 50% of total sales, relative consumption has remained at about 45%. Although there has been some growth in this sector in response to lower prices, it has been mitigated by fuel substitution and increased efficiency (technological improvements and capital stock turnover), particularly in the mining and pulp and paper industries.

Regional Review
Atlantic

The rise in sales of heavy fuel oil since 1985 has been largely centred in the Atlantic region, which in 1987 accounted for 46% of national demand. In fact, Atlantic demand has accounted for almost two thirds of the Canadian heavy fuel oil growth from 1985 to 1987. In 1987, sales increased dramatically, up by 30% to 8 400 m^3/d from 1986 and represented around three quarters of the 11% increase in total oil product consumption in the Atlantic region.

Moreover, heavy fuel oil currently accounts for 37% of oil consumption in the region, the largest share in the country reflecting a lack of alternative fuels, (i.e. natural gas and hydro electricity) relative to other regions. As mentioned in the previous section, after a slight drop in heavy fuel oil sales for electricity generation in 1986, demand in 1987 rose by more than 60%. The major contributor to this increase was low water levels which lowered hydro generation capabilities.

While other sectors, with the exception of the commercial sector, have shown demand growth since 1985, the strongest area has been the transportation sector, up 75%, reflecting a healthy economy and increased marine bunker demand.

As illustrated in Table 1.5.1, in comparison with 1985, heavy fuel oil sales in the first nine months of 1988 have increased in three of the four provinces in the Atlantic region. The largest increase was registered in New Brunswick where consumption almost doubled in the three years and now represents over 50% of Atlantic heavy fuel oil consumption. As mentioned previously, most of the increase was a result of thermal electric generation requirements.

Table 1.5.1
Heavy Fuel Oil Sales
(first nine months)

	1985	1988	Change
	(000 m^3/d)		(%)
Newfoundland	1.6	1.5	(6)
Nova Scotia	1.7	2.9	70
P.E.I.	0.1	0.2	50
New Brunswick	2.9	5.6	93
Total	6.3	10.1	60

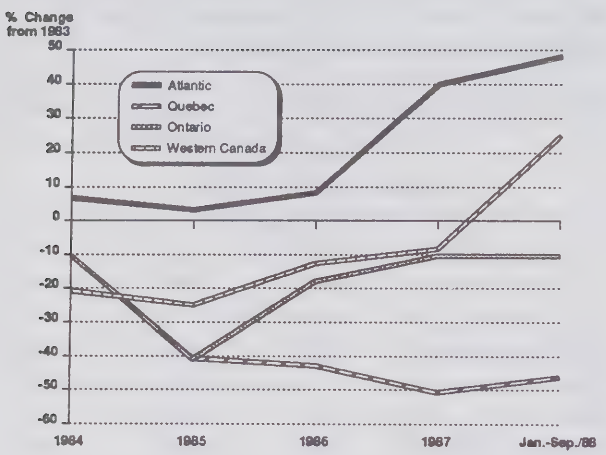
Quebec

In contrast to other regions, demand for heavy fuel oil in Quebec has declined every year, except in 1986 when there was a 5% increase. In 1987, consumption averaged 4 500 m^3/d, and represented only 40% of the volume consumed in 1983. The largest declines have been in the industrial and commercial sectors.

Despite lower prices and strong economic growth over the last three years, the increased use of alternative fuels was the major factor contributing to the decline. Incentives from Hydro Quebec to market surplus electricity, and natural gas market penetration, had a strong negative impact on heavy fuel consumption.

In March 1988, however, Hydro Quebec's surplus electricity and dual energy program which offered firms grants and very low rates to operate electric boilers was partially phased-out and presumably contributed to a 28% increase in heavy fuel oil consumption during the first nine months of 1988. This program will be completely eliminated by the end of November 1988; therefore, there is a possibility that a number of companies may revert to use of heavy fuel oil or natural gas, depending on relative prices.

Figure 1.5.3
Regional Heavy Fuel Oil
Consumption Trends



Ontario

In contrast to Quebec, sales in Ontario have been increasing since 1985, reaching 3 000 m^3/d in 1987, a 20% increase. Despite this increase, heavy fuel oil sales in Ontario still represent less than 20% of total heavy fuel oil consumption in Canada. In response to the strong demand growth, both buyers and sellers have also built up stocks thus adding to apparent demand. The strongest growth was in the industrial sector, which accounts for over 50% of Ontario consumption, and the transportation sector.

During the first nine months of 1988, Ontario heavy fuel oil sales rose by a further 17% to 3 500 m^3/d from last year. As mentioned previously, good economic performance contributed to the increase supported by some switching from natural gas. It is also interesting to note that increased heavy fuel oil availability, lower prices and higher electricity demand led Ontario Hydro to re-open its oil-fired Lennox generating station late last year, after having been "moth-balled" five years ago. The small 1,100-megawatt plant was brought back into operation in order to help meet electricity demand during peak hours. An annual contract for 95 000 m^3 of heavy fuel oil was signed to fuel the station.

Western Canada

Over the past three years, sales in Western Canada recorded a 5% annual annual growth rate; however, the region still represents less than 15% of total heavy fuel oil consumption. (British Columbia accounts for over 80% of heavy fuel oil consumption in Western Canada). Between 1985 and 1987, British Columbia registered an overall growth of 23%, mainly as a result of a strong increase in demand for marine bunker fuel by both domestic and foreign vessels. The rise was partly the result of a reduction in provincial taxes on heavy fuel used as ship bunker fuel.

Despite the growth in the last three years, and continued competitive prices, the future of heavy fuel oil consumption remains uncertain. Environmental legislation controls could place constraints upon the use of many petroleum products, including heavy fuel oil. Also, concerns about pollution and a potential global warming trend may put pressure on industry to lower its demand for heavy fuel oil through increased conservation and fuel substitution.

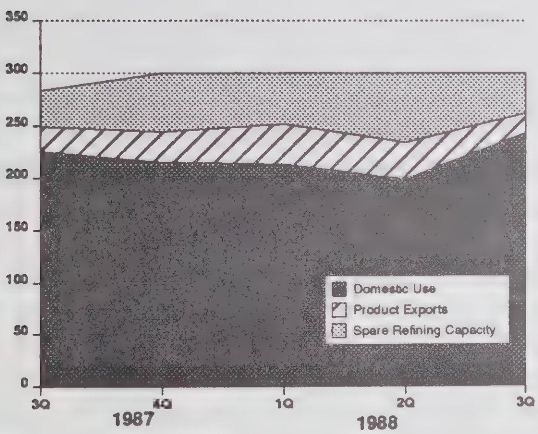
2. Refinery Utilization

- *Overall refinery utilization rates remain at relatively high levels.*

Crude run to stills during the third quarter of 1988 averaged 264 000 m^3/d, up 4% or 11 000 m^3/d, for the most part the result of higher processing in the Atlantic region. Although refining capacity increased almost 4% (11 000 m^3/d) to 300 000 m^3/d, the national average refinery utilization rate remained unchanged at 88%. Refinery utilization is usually quite high in the third quarter.

Figure 2.1.1
Refinery Utilization

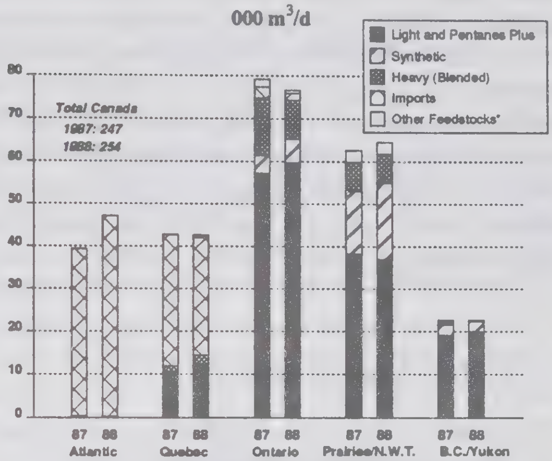
000 m^3/d



Refinery receipts of Canadian crude oil during the third quarter of 1988 averaged 174 000 m^3/d, a 2% increase from 1987 (excludes 4 000 m^3/d of gas plant butanes) with all of the increase in the light crudes and equivalent category. Conventional light crude oil receipts at 125 000 m^3/d were higher by 2% (3 000 m^3/d) as Ontario refiners switched back to lighter crudes. Relatively full production at both synthetic plants supported domestic deliveries of 26 000 m^3/d, a 25% increase over 1987.

Figure 2.1.2
Crude Oil and Equivalent Receipts by Region
(Third Quarter)

000 m^3/d



Refinery utilization rates in the Atlantic fell slightly to 76%, despite the recommissioning of a refinery to process for export purposes for the most part. Quebec receipts at 45 000 m^3/d were slightly less than 1987, so that refinery utilization dropped one percentage point to 94%. Domestic crude receipts were up 3 000 m^3/d, although these receipts were more than offset by a reduction in imported crude.

Ontario refinery utilization rose one percentage point to 88%. Light and equivalent receipts jumped 4 000 m^3/d to 65,000 m^3/d, as the mix between light and heavy returned to more historical proportions than was the case in 1987.

Table 2.1.1
Refinery Utilization
(Third Quarter)

	1986	1987	1988
		(% Utilization)	
Atlantic	74	77	76
Quebec	88	95	94
Ontario	85	87	88
Prairies	87	88	90
B.C.	85	96	96
Canada	84	88	88

Although the Consumers Co-op refinery was shutdown for over a month while undergoing modifications to complete the link with the Newgrade upgrader, refinery utilization in the Prairies nevertheless increased. The 90% utilization rate, (73 000 m^3/d) was achieved through higher processing in the early part of the period. Third quarter consumption of petroleum products in the Prairies increased 2% following a drop in the second quarter. Also more products, both fully and partially processed, were shipped to British Columbia.

3. Pipeline Utilization

- *In general, most major oil pipelines out of western Canada were operating near capacity, despite some capacity additions since last year.*
- *Further expansion plans under consideration.*
- *Overall pipeline deliveries to Montreal increase but pipeline capacity utilization rates remain relatively low.*

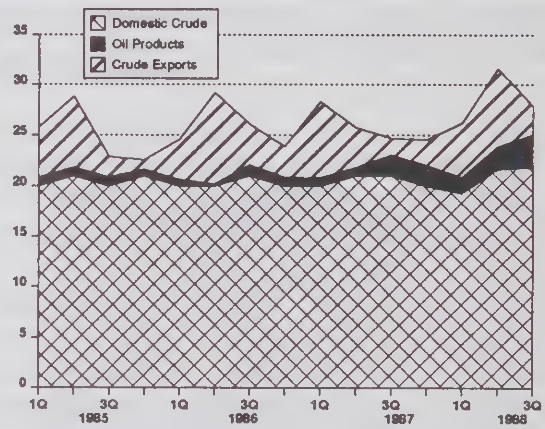
3.1 Trans Mountain Pipe Line

Trans Mountain Pipe Line (TMPL) throughput during the third quarter of 1988 was 28 000 m^3/d, down 9% from the second quarter but 12% higher than in the third quarter of 1987. Crude throughput was exclusively light and equivalent, as heavy crude (mainly for export) dropped from 1 000 m^3/d in 1987 to zero in 1988. The decline in heavy crude deliveries in part reflected falling prices and some shut-in at marginal wells. Crude receipts by Canadian refiners in British Columbia were slightly higher in 1988 at 22 000 m^3/d, than a year earlier.

Exports via the Trans Mountain system totalled almost 3 000 m^3/d, close to 75% higher than in the third quarter of 1987. Part of this increase reflects capacity constraints on the IPL system (there were virtually none in the third quarter of 1987), which led producers to utilize the TMPL system. Of the higher volume, half was delivered by tanker to Far East destinations, while pipeline exports to Washington State accounted for the remainder.

Petroleum product deliveries continued to grow, reaching 3 000 m^3/d, a 50% jump from 1987, and the highest level since product movements began. Part of this increase reflects refinery rationalization occurring in British Columbia whereby west coast demand was met with more finished and partially refined product shipments from Edmonton.

Figure 3.1.1
Trans Mountain Pipe Line Deliveries
000 m^3/d



As outlined in the second quarter of 1988 issue of the 'Canadian Oil Market' report, in August, the National Energy Board authorized Trans Mountain to proceed with improvements to its system to accomodate exports of up to 6 000 m^3/d of heavy crude by 1990. The Board's decision has since been appealed by two groups representing environmental and residential interests in the Burnaby area of British Columbia, where construction of additional storage tankage is planned.

During the same hearings, the pipeline company was turned down in its request for a second expansion based on anticipated future movements of methanol and methyl tertiary butyl ether (MTBE) from Edmonton. The Board denied the request because the necessary additional terminalling facilities had not been requested. Since then, Trans Mountain and Nestlé Oy of Finland have announced plans to build a MTBE plant in Edmonton, with much of the initial production expected to be exported to the California market. As a result, it is expected that the Board will be asked to reconsider the second pipeline expansion.

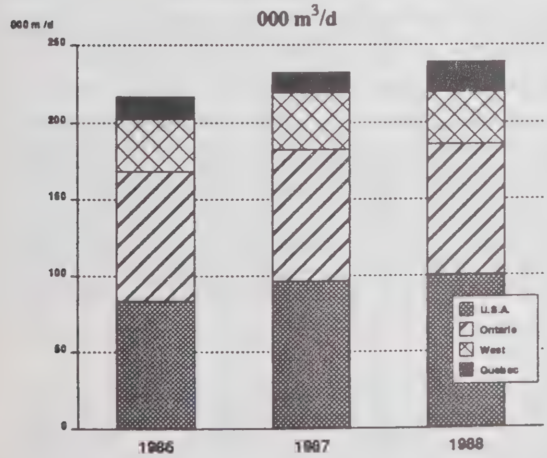
3.2 Interprovincial Pipe Line

Total IPL deliveries of crude oil and other hydrocarbons, including petroleum products and natural gas liquids, during the third quarter of 1988 averaged 239 000 m^3/d, a 3% increase over the volume moved in the same quarter a year earlier, reflecting additional pipeline capacity installed late in 1987.

The largest gain occurred in Quebec deliveries which increased by 45% to almost 19 000 m^3/d. Deliveries to the United States were also higher, up 4% to 101 000 m^3/d, and accounted for 42% of total deliveries, while western Canadian deliveries were down 6% to 34 400 m^3/d. Ontario receipts were unchanged in total (35% of movements) although the mix was different. Deliveries of heavy crude continued to rise, up 5 000 m^3/d, mainly to U.S. markets.

Heavy crude made up 30% of total deliveries while total light crude were deliveries were unchanged at 119 000 m^3/d from 1987. Drops in the west and the United States offset increases in the eastern part of the system. Deliveries of synthetic crude were higher by about 3 000 m^3/d, the increment split almost evenly between the United States and Ontario. The additional synthetic volumes reflected higher output in 1988 at both plants. (See production section 4.1.)

Figure 3.2.1
Total IPL Deliveries
000 m^3/d

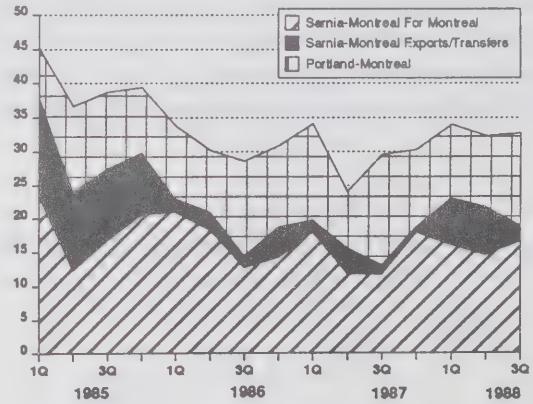


For the future, IPL continues to review various scenarios in relation to capacity requirements. Earlier estimates of $1.1 billion for a phase IV expansion have been revised down to about $800 million for an additional 32 000 m^3/d. IPL is now also giving consideration to the possibility of adding capacity through a series of smaller, phased expansions, instead of one large expansion.

3.3 Montreal Pipeline Utilization

Overall pipeline deliveries of crude oil to Montreal during the third quarter of 1988 were 32 000 m^3/d, up by about 3 000 m^3/d over the same period of 1987. The Sarnia-Montreal portion of the IPL system handled close to an additional 6 000 m^3/d for a total of 19 000 m^3/d, which yielded an utilization rate of 36%. The Portland system was used to deliver almost 14 000 m^3/d of imported crude oil, a drop of about 2 000 m^3/d. At this level, the system operated at 45% of capacity.

Figure 3.3.1
Crude Oil Deliveries to Montreal
000 m^3/d



The additional deliveries to the Montreal area reflected the higher product demand in the Quebec marketing region and increased transfers and exports out of the Montreal. Part of the reason for the higher domestic crude oil deliveries (up 43%) was the greater capacity on the western section of the IPL system and increased crude availability which allowed refiners to utilize more Canadian crude, particularly since it was competitively-priced with import alternatives.

Of the additional 6 000 m^3/d of domestic crude transported by the Sarnia-Montreal pipeline, 4 000 m^3/d of it was heavy crude. More than half of this volume was exported through Montreal. (Appendix I provides current capacities of major oil pipelines in Canada.)

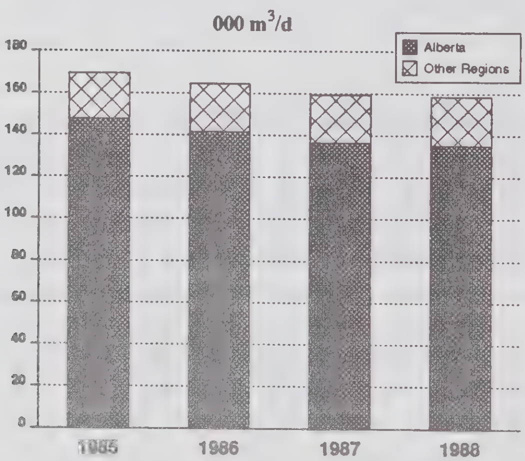
4. Crude Oil Supply and Disposition

- *Conventional light crude oil productive capacity virtually unchanged over last year while rate of growth in heavy crude oil slows.*
- *Sales of light crude oil to Canadian markets grew somewhat faster than sales to export markets whereas heavy crude sales showed a reverse pattern.*
- *Several development projects were announced during the quarter.*

4.1 Light Crude Oil Supply and Disposition

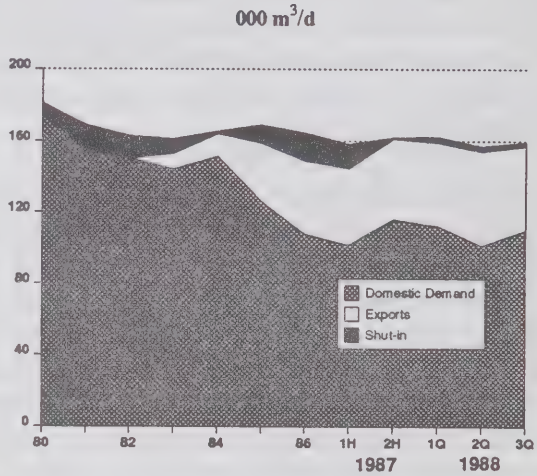
Despite declining prices as compared to last year, during the third quarter of 1988 productive capacity of conventional light and medium crude, at 159 000 m^3/d, was virtually unchanged from the same period in 1987. A slight decrease in Alberta capacity, to 136 000 m^3/d was offset by an increase in other producing regions.

Figure 4.1.1
Conventional Light and Medium Crude Oil Productive Capacity
Third Quarter



Although the June 1987 IPL expansion permitted full productive capacity utilization in the third quarter of 1987, additional crude supply has put pressure on the IPL system throughout 1988, and resulted in light crude shut-in of about 2 000 m^3/d in the third quarter. Production from conventional fields in Alberta dropped to about 133 500 m^3/d, 3 000 m^3/d less than in 1987. Output from outside Alberta increased 3% to 23 500 m^3/d, of which 5 000 m^3/d were produced in the Norman Wells area of the Northwest Territories.

Figure 4.1.2
Conventional Light Crude Capacity and Disposition



Although Syncrude production was reduced in August and September as a result of minor maintenance work, total synthetic crude production during the third quarter was more than 33 000 m^3/d (5 000 m^3/d or 18% higher than in 1987). At Suncor, output jumped 25%, reflecting full production compared to the situation in 1987 when part of the plant was shutdown for maintenance. The Syncrude Capital Expansion Program (CAP) (see section 4.3) which was completed in September 1988, contributed to production in excess of 24 000 m^3/d, about 3 000 m^3/d higher than a year earlier.

Although some concerns remain about the long-term availability of condensate (pentanes plus) for diluent use, total third-quarter production of over 16 000 m^3/d was equal to the 1987 level, as was the 6 400 m^3/d delivered as refinery feedstock. The balance was used as heavy crude diluent.

Table 4.1.1
Light Crude Oil and Equivalent Production and Disposition (Third Quarter)

	1987	1988 (000 m³/d)	Change
Production			
Alberta	136.6	133.5	(3.1)
Other	22.8	23.5	0.7
Synthetic	27.8	33.2	5.4
Pentanes Plus (ex. diluent)	6.4	6.4	---
Total	**193.6**	**196.6**	**3.0**
Inv.(Draw)/Build	(0.9)	(7.5)	(6.6)
Net Supply	194.5	204.1	9.6
Demand			
Atlantic	0.0	0.0	0.0
Quebec	10.5	12.5	2.0
Ontario	61.6	65.4	3.8
Prairies	53.2	55.0	1.8
B.C.	21.7	22.4	0.7
Domestic Demand	**147.0**	**155.3**	**8.3**
Exports	**47.5**	**48.8**	**1.3**
Total Demand	**194.5**	**204.1**	**9.6**

Total light and equivalent crude oil output during the third quarter of 1988 was 197 000 m^3/d, a 1.5% increased over the same period of 1987. This represented about 71% of all crude production in Canada during the period, a drop of one percentage point from the year prior.

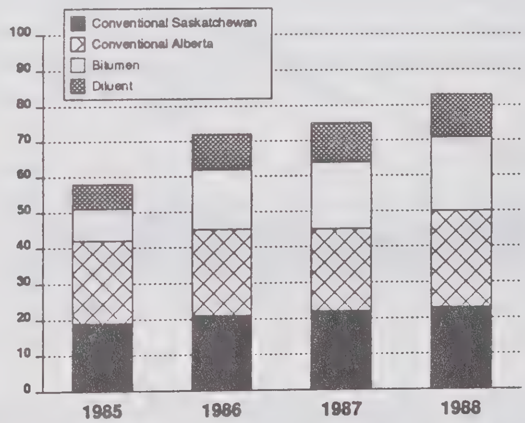
Almost 75% of the total Canadian light and equivalent crude production was received by Canadian refiners with the balance delivered to export markets. Most of the additional deliveries were synthetic crude, the availability of which was reduced in 1987.

4.2 Heavy Crude Oil

Despite lower crude oil prices, unblended conventional heavy crude oil productive capacity during the third quarter 1988 rose to 50 000 m^3/d an increase of 9% from a year ago. The federal government program, CEDIP, (Canadian Exploration and Development Incentive Program) contributed to higher drilling activity, particularly in the Bow River area of Alberta because of the relatively short lead-time to consequent production. In addition, the approaching deadline to reduced federal government grants incited producers to accelerate exploration activity.

Most of the supply additions occurred in Alberta, up 16% to 27 000 m^3/d. Saskatchewan productive capacity rose marginally, to 23 000 m^3/d. In contrast to last year, when available supply was divided almost evenly between Alberta and Saskatchewan, the Alberta share accounted for 54%.

Figure 4.2.1
Heavy Crude Oil Productive Capacity
(Third Quarter)
000 m³/d



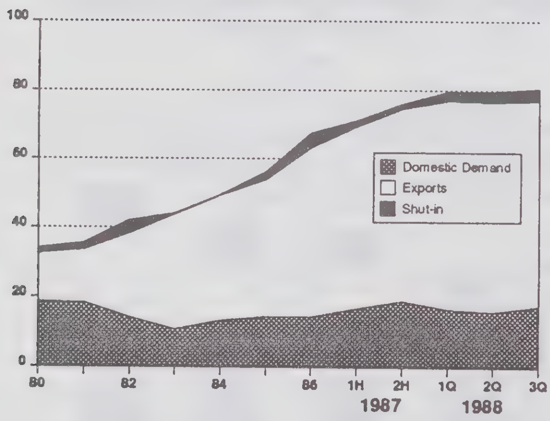
In contrast to 1985 and 1986 when raw bitumen supply doubled each year, the growth slowed substantially, to only 7% in 1988. This lower growth rate was related to declining world oil prices, which have had the effect of slowing development of projects.

Pentanes plus requirements (including recycled) for blending purposes averaged 12 000 m^3/d, up only 500 m^3/d from a year ago. Over the last year the rate of growth in the use of pentanes plus as a blending agent for heavy crude has declined for a variety of reasons. These include greater movement of Bow River crude, which requires a marginal amount of diluent, increased use of recycled diluent, which rose slightly to 1 300 m^3/d, and some marginal use of refinery naphtha as a blending agent. It is also possible that producers were willing to pay a penalty to move heavy crude oil at a higher viscosity than required by the IPL system.

Total blended heavy crude capacity was up more than 8% from last year, to 81 000 m^3/d, representing 29% of total available supply of Canadian crude oil and equivalent.

Figure 4.2.2
Heavy Crude Oil Productive Capacity and Disposition

000 m^3/d



Heavy crude production averaged 77 000 m^3/d in the third quarter, up 4% from a year ago. Unused capacity was also up - 4 000 m^3/d from 1 500 m^3/d. Although lack of transportation capacity contributed to the increase in shut-in, a more important factor was falling crude oil prices. Since peaking at more than $US 21/bbl in mid-1987, light crude oil prices at Chicago declined to about $US 15/bbl by the end of the third quarter 1988. Heavy crude prices fell to $US 11/bbl to 13/bbl over the same period (see section 8). As a result heavy crude producers began to delay required maintenance of some marginal wells in the third quarter. As well, in early October both Shell Canada and Esso Resources announced slowdowns in their respective oil sands expansion projects because of low prices. Sustained prices at October levels will have a cooling effect on the growth of near-term heavy crude supply.

Table 4.2.1
Disposition of Canadian Heavy Crude Oil
(Third Quarter)

	1987	1988	Change
	(000 m^3/d)		
Production			
Conventional	43.4	45.9	2.5
Bitumen	19.2	20.6	1.4
Diluent	11.2	11.8	0.6
Total	73.8	78.3	4.5
Inv.(Draw)/Buid	(2.2)	(3.7)	1.5
Total	**76.0**	**82.0**	**6.0**
Demand			
Atlantic	0.5	0.4	(0.1)
Quebec	1.5	2.0	0.5
Ontario	13.2	8.9	(4.3)
Prairies	6.8	6.9	0.1
B.C.	0.7	0.3	(0.4)
Domestic Demand	**22.7**	**18.5**	**(4.2)**
Exports	**53.3**	**63.5**	**10.2**
Total Demand	**76.0**	**82.0**	**6.0**

As illustrated in figure 4.2.2, virtually all incremental production of heavy crude has been exported during the 1980's. In fact, demand by Canadian refiners fell 4 000 m^3/d in the third quarter, to 18 500 m^3/d compared with the same period a year ago (table 4.2.1.). Most of the decline occurred in Ontario, down by over 4 000 m^3/d to 9 000 m^3/d, reflecting some substitution to synthetic and conventional light crude oil and reduced asphalt demand. Deliveries to Quebec, however, partly offset this decline with an increase of 500 m^3/d to 2000 m^3/d. Heavy crude oil exports were about 64 000 m^3/d (mainly to the United States) accounting for 81% of total heavy crude oil production (see Section 5.1 for more details on exports).

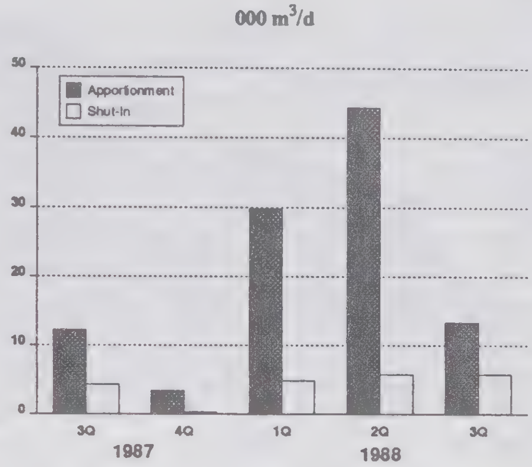
It should be noted that the Newgrade heavy crude upgrader began operation in December. Located in Regina, Saskatchewan, it will be the first heavy crude oil upgrader in Canada and is set to upgrade some 8 000 m^3/d of heavy oil from both Alberta and Saskatchewan to synthetic crude.

The upgrader is integrated with the CO-OP refinery, which had been refining conventional light crude oil as feedstock. According to Newgrade officials a heavy/light crude price differential of \$25/m^3 is required to make the upgrader profitable. The current differential (early October) is about \$32/m^3.

IPL Apportionment

IPL apportionment of pipeline space during the third quarter of 1988 averaged 7% or 13 000 m^3/d. Crude oil supply exceeded pipeline capacity in July and September, while in August the apportionment was related to a surplus in demand. Pipeline maintenance also contributed to the apportionment. Despite lower apportionment than the previous quarter, down from 19% to 7%, shut-in rose marginally to 6 000 m^3/d, of which two thirds was heavy crude oil. Much of the heavy crude downturn reflected lower crude oil prices which caused a slowdown in bitumen development and the fact that marginal wells were shut-in.

Figure 4.2.3
IPL Apportionment and Crude Oil Shut-In



4.3 Syncrude Canada Anniversary

The Syncrude Canada Ltd. operation situated at Fort McMurray in northern Alberta, celebrated its tenth anniversary in August. Deliveries from the oil sands plant, which became operational in July 1978 after almost five years of construction, arrived in Edmonton in August of that year. Start-up difficulties limited production to slightly less than 5 000 m^3/d during the first five months of operation, well below the design capacity of 20 000 m^3/d.

Although Syncrude had purchased some technology from Suncor, the mining and extraction process was still fairly new. Nonetheless, Syncrude managed to increase output almost every year (fig 4.3.1). The only exception was in 1984 when an August fire resulted in a partial closure of the plant and lower-quality output.

Following a number of improvements based on experience and some additions to the facilities, production in 1987 reached almost 22 000 m^3/d. (For 1988, output is forecast at almost 24 000 m^3/d). The Syncrude contribution to Canadian light oil production has grown from insignificant in the first two years to 12% in 1987.

Figure 4.3.1
Synthetic Crude Production

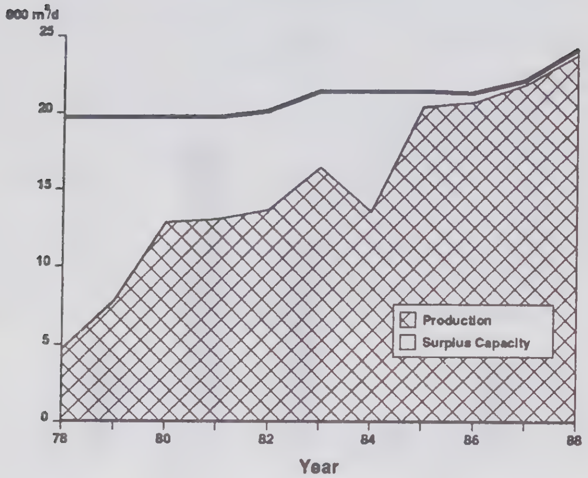
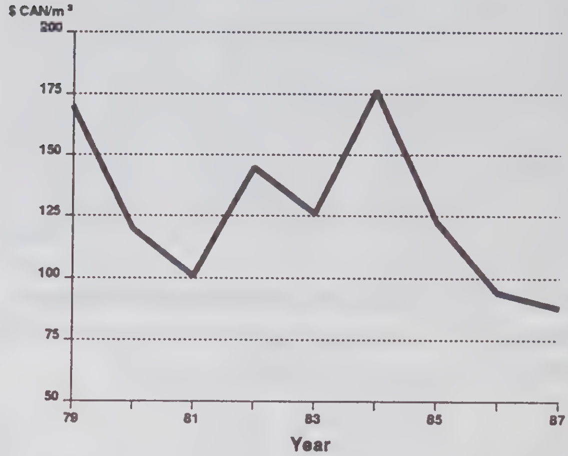


Figure 4.3.2
Syncrude Average Production Costs



In the third quarter of 1988, Syncrude completed a five year, $500 million Capacity Addition Program (CAP), which increased both efficiency and capacity. As of early September, Syncrude's potential sustained output reached 26 000 m^3/d. Part of the efficiency increase will arise from the lengthened period between major maintenance programs. Further, it is interesting to note that despite higher production overall, sulphur emissions will be reduced, which represents a major environmental improvement.

As illustrated in fig 4.3.2, dealing with new technology and methods, particularly in the earlier years, resulted in high production costs. Fortunately, world oil prices at the time were also high, which encouraged the Syncrude participants to continue with the project. While production costs have generally been declining at Syncrude, lower crude prices since 1986 have provided a further cost-cutting impetus. Many factors contributed to the cost reduction, including technological improvements, lower energy inputs, a better delivery system, higher product quality through the introduction of hydrocracking and increased employee productivity. The corporation's objective is to keep operating costs constant, ie; reduce costs by enough to offset inflation. In 1987 production costs averaged $14.85/bbl ($93.50/m^3).

For the future, Syncrude has another expansion planned, which would increase production by a further 13 000 m^3/d (50%). Construction of the $4 billion addition could start in 1989 with plant start-up in 1993 for stage 1 and 1996 for stage 2.

4.4 Domestic Crude Oil Supply - 1989

Recently, the National Energy Board prepared a 1989 crude oil supply forecast, based on international crude prices of $US15 to $16/bbl in 1989. Under this scenario conventional light crude oil productive capacity is expected to fall 4% to 154 000 m^3/d, from the 1988 level. Most of the decline is forecast to occur in Alberta where available supply could fall from 136 000 m^3/d to 131 000 m^3/d, in part as a result of low crude oil prices (It becomes more difficult to justify expenditures for field development and maintenance of marginal wells) and reduced drilling activity. The 1989 decline in Alberta will represent the fourth consecutive annual decline in conventional light crude oil productive capacity.

Despite a slight increase from Norman Wells, (up to 5 000 m^3/d) available supply from other conventional oil producers outside Alberta should decline marginally to less than 23 000 m^3/d in total.

Synthetic production (adjusted for maintenance work) should reach a record high of 34 000 m^3/d, up 8% from 1988. This increase, which is almost evenly split between Suncor and Syncrude, reflects the completion of the Capacity Addition Program (CAP) at Syncrude and full production at Suncor. Over the past few years, synthetic plant operators have attempted to reduce operating cost in order to remain competitive in the face of declining crude prices. Currently the operating costs are estimated at $14-$15/bbl. Pentanes plus availability is expected to average almost 20 000 m^3/d, up 7%, mainly reflecting higher natural gas production in order to satisfy both the domestic and export markets.

Table 4.4.1
Available Supply of Western Canadian Crude Oil and Equivalent

	1989	1988 (000 m^3/d)	1987
Conventional Light			
Alberta	131.1	136.0	136.9
B.C.	5.3	5.3	5.7
Manitoba	1.9	2.1	2.1
Saskatchewan	10.9	10.9	10.7
Other	4.8	4.9	4.2
Total Conventional	**154.0**	**159.2**	**159.6**
Synthetic			
Suncor	9.2	7.8	6.8
Syncrude	25.0	23.9	21.7
Total Synthetic	**34.2**	**31.7**	**28.5**
Pentanes Plus (ex diluent)	7.5	6.6	6.9
Total Light and Equivalent	**195.7**	**197.5**	**195.0**
Heavy Crude Oil			
Conventional	46.9	48.1	44.3
Bitumen	20.2	20.4	18.4
Total Heavy	**79.3**	**80.2**	**73.5**
Total Supply	**274.7**	**277.7**	**268.5**

Total conventional light, medium and equivalent crude available supply for 1989 is expected to be 196 000 m^3/d, down 1% (2 000 m^3/d) from 1988 levels.

Unblended conventional heavy crude oil availability is forecast to fall by 2% to 47 000 m^3/d, reflecting the impact of lower oil prices on capacity. As a result, the natural decline of existing wells may become more apparent, after several years of increases. Raw bitumen production is anticipated to decline slightly to 20 000 m^3/d from 1988, rather than a previously-expected increase of 10% to 15%. This outcome would represent the first year-over-year decline in bitumen capacity. Low oil prices have contributed to the slowdown of several projects such as Cold Lake and Peace River, as noted in section 4.2. Total unblended heavy crude supply should average 67 000 m^3/d, down almost 3%. (An increase of 9% was recorded in 1988.)

As a result of forecast declines in both heavy and light crude supply, total available crude oil supply in 1989 is forecast to be down 4 000 m^3/d, to 275 000 m^3/d - the first overall drop since 1982.

4.5 Oil Projects

During the third quarter plans for three major oil development projects were announced.

Hibernia

In July the Governments of Canada and Newfoundland, along with a consortium of companies headed by Mobil Oil, signed an agreement which could lead to the eventual production of crude oil from the Hibernia oilfield off the coast of Newfoundland.

The Hibernia oilfield, with existing reserves of at least 3.3 to 4.1 billion cubic metres, was discovered in 1979. After the field was delineated and appraised in the early 1980s, there were 2 1/2 years (beginning with the Atlantic Accord in early 1985) of steady negotiations between the governments and sponsors before the agreement was reached.

The federal government will contribute up to $1 billion in grants and $1.6 billion in loan guarantees while Newfoundland and Labrador will remove the retail sales tax on project capital costs. In return, given certain oil price levels, both governments will share in project revenues.

The construction phase of the $8.5 billion project should be completed in 1996. Production is expected to average 17 000 m^3/d of light crude, representing 7% of the light crude oil requirements in Canada at that time, and 50% of petroleum product demand in the Atlantic region. The Hibernia field represents about 50% of known reserves in the area, although it is estimated that the total potential resources offshore Newfoundland may be 10 times the Hibernia established reserve base.

Heavy Oil Upgrader

In September, the governments of Canada, Alberta and Saskatchewan reached a joint venture agreement with Husky Oil Limited to build and operate a $1.3 billion heavy crude oil upgrader to be located near Lloydminster on the Alberta-Saskatchewan border. The construction of the plant is expected to start in 1989 with completion in 1992. The upgrader will have the capacity to convert heavy crude into about 7 300 m3/d of synthetic crude. The Government of Canada will contribute 31.6% of the equity; Alberta 24.2%, Saskatchewan 17.5% and Husky Oil 26.7%. The project has been discussed, on and off, since 1982, when it was first put forward by Husky.

Oil Sands Mining Project

A third project was also announced in September. The Other Six Leases Operation (OSLO), which is a six company joint venture led by Esso Resources Ltd., reached an agreement with the Federal and Alberta governments on financial assistance for the construction and operation of Canada's third oil sands mining project. The governments will jointly contribute $850 million toward construction costs. Under lower price assumptions, additional contributions, of up to $160 million, could also be provided. The agreement also stipulates that governments will provide loan guarantees ($1.2 billion) and interest assistance (up to $250 million). The project, with an estimated capital cost of $4.1 billion, will be a fully integrated operation similar to Syncrude and Suncor, and is expected to produce 12 000 m3/d of high quality synthetic crude. Construction is set to begin in 1991 with production to follow in 1996.

The construction and operational phases of these projects will have significant regional development impacts, a major reason for government support for these projects. They will also make a contribution to Canada's future oil supply and the technical evolution of the Canadian oil industry.

5. Exports and Imports

- *Crude oil exports continue to rise and now account for 40% of total production.*

- *Crude oil imports increase but most related to processing for re-export arrangements in the Atlantic region.*

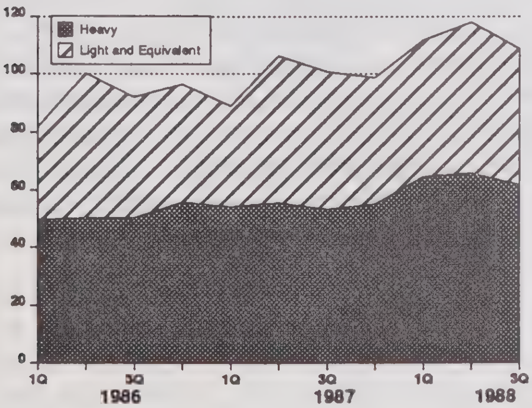
- *The North Sea area supplies more than half of all Canadian crude oil imports.*

- *Over the past three years, higher volumes exported have not quite offset the impact of price declines and higher exchange rates on producers' revenues.*

5.1 Crude Oil Exports

Crude oil exports in the third quarter of 1988 averaged 110 100 m^3/d, an increase of 9 000 m^3/d (9%) over the same period a year earlier. The additional exports, reflecting the continuing strength of U.S. refinery demand, the increased availability of Canadian crude oil for export (in particular, heavy crudes) and additional pipeline capacity to U.S. markets, were split at a ratio of 56:44 in favour of heavy crudes over light and equivalent. This compares with a 53:47 ratio a year earlier.

Figure 5.1.1
Crude Oil Exports
000 m^3/d



Exports of heavy crude oil totalled 62 000 m^3/d, up 8 700 m^3/d (16%) over the same period last year, while exports of light and equivalent crudes increased marginally, to 48 100 m^3/d. As a percentage of total Canadian crude oil production, these exports represented about 40% of production, 4 percentage points higher than last year (heavy exports were 78% of production, light and equivalent crudes, 24%).

As illustrated by table 5.1.1, the bulk of Canadian crude oil exports were destined for the United States, in particular the U.S. midwest (Petroleum Administration for Defense (PAD) Districts II and IV). Relatively small but significant volumes were shipped offshore to such diverse far east destinations as South Korea and Taiwan. It is interesting to note, that while most of the U.S. receipts of Canadian crude were delivered by pipeline, about 3% of these receipts were tankered through the port of Montreal to non-traditional destinations along the U.S. eastern seaboard, and represented more than 20% of PADD I deliveries. (See Appendix II for PAD District locations.)

PADD II, is traditionally the recipient of the largest share of Canadian crude oil exports. Third-quarter receipts, representing over three quarters of all Canadian exports to the United States, averaged 83 400 m^3/d, up 3 300 m^3/d (4%) from last year. Heavy crude oil exports increased by 5 800 m^3/d (12%), to 53 800 m^3/d, while light and equivalent crude oil exports declined by 2 500 m^3/d (8%), to 29 600 m^3/d.

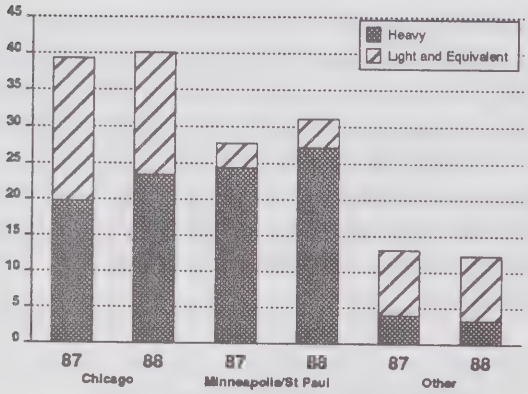
Table 5.1.1
Crude Oil Exports by Destination

	Light		Heavy		Total	
	1987	1988	1987	1988	1987	1988
	(000 m^3/d)					
United States						
PADD I	6.6	7.7	0.9	4.1	7.5	11.8
PADD II	32.1	29.6	48.0	53.8	80.1	83.4
PADD III	0.0	0.0	0.0	0.0	0.0	0.0
PADD IV	8.2	8.2	3.4	3.9	11.6	12.1
PADD V	0.6	1.4	1.0	0.0	1.6	1.4
Total U.S.	**47.5**	**46.9**	**53.3**	**61.8**	**100.8**	**108.7**
Offshore	0.0	1.2	0.0	0.2	0.0	1.4
Total Exports	**47.5**	**48.1**	**53.3**	**62.0**	**100.8**	**110.1**

As illustrated in figure 5.1.2, Canadian exports of crude oil to PADD II were concentrated in the Chicago, Illinois refining area, where total receipts averaged 40 100 m^3/d, up marginally from the same period last year. Although the Chicago area was the largest recipient, at about 48% of PADD II deliveries and 37% of overall Canadian crude oil exports to the United States, most of the third-quarter increase occurred in the Minneapolis/St. Paul refining area of Minnesota. Heavy crudes accounted for the largest proportion of this increase, as deliveries increased by 2 800 (12%), to 27 200 m^3/d with the volume of light crudes relatively unchanged.

Figure 5.1.2
Canadian Crude Oil Deliveries to PADD II
(Third Quarter)

000 m^3/d



Deliveries to 'other' refining areas within PADD II, of mainly light crudes, to destinations such as Superior, Wisconsin; Detroit, Michigan; Toledo, Ohio and Laketon, Indiana, declined slightly.

PADD I registered the highest growth rate in Canadian crude oil receipts. Demand in PADD IV, Canada's second largest U.S. market area (Montana and Wyoming), remained strong. As a result, the Rangeland pipeline delivery system operated at close to capacity throughout the quarter.

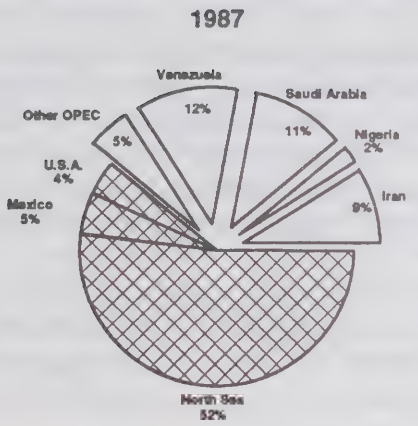
Total U.S. crude oil imports for the third quarter (excluding Strategic Reserve imports), is estimated at 795 000 m^3/d. Of this volume, Canadian imports represented about 14%, second only to Saudi Arabia at 17%, and followed closely by Mexico and Nigeria. Crude oil imports, as a percentage of total U.S. refinery crude oil demand (including domestic inputs) amounted to about 40%. Canada's share of this demand was just over 5 percentage points.

5.2 Crude Oil Imports

Canadian refiners imported 75 900 m^3/d of foreign crude during the third quarter of 1988, an increase of 3 500 m^3/d (5%), over the same period a year earlier. Most of this increase can be traced to the reactivation of the Come-by-Chance refinery to process imported crude, largely for re-export as products to the New England area.
Imports from OPEC countries increased by 13%, to 31 000 m^3/d, to represent a 41% market share of total Canadian import requirements, up 3 percentage points from last year. Venezuela and Saudi Arabia were the largest OPEC suppliers, capturing a 13% and 9% market share respectively, followed closely by Nigeria at 8%.

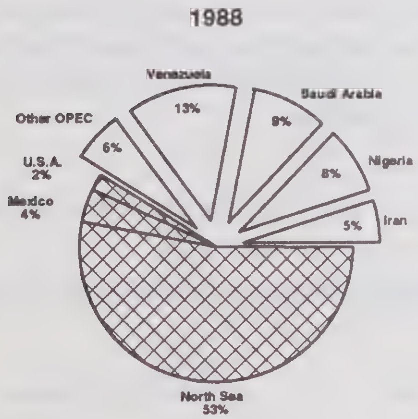
Although the non-OPEC share of the Canadian import market declined in percentage terms, imports in volumetric terms remained unchanged at 45 200 m^3/d. The North Sea area maintained its position as the major Canadian supplier, accounting for 53% of total imports (and 90% of non-OPEC imports). Imports from Mexico and the United States on small volumes, declined by 27% and 52% respectively.

Figure 5.2.1
Sources of Crude Oil Imports
(Third Quarter)



000 m^3/d

Total 72 000 m^3/d
Non-OPEC 62%
OPEC 38%

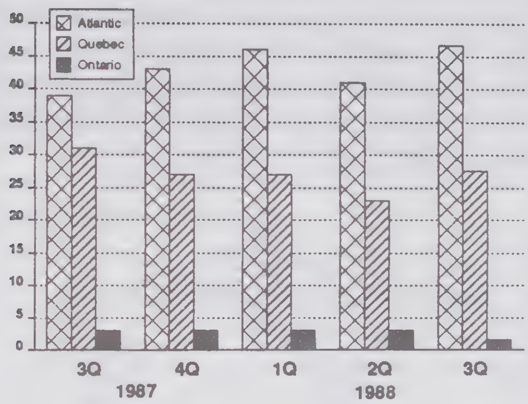


Total 76 000 m^3/d
Non-OPEC 59% OPEC 41%

On a regional basis, Atlantic crude oil imports of 46 700 m^3/d, were 7 800 m^3/d (20%) higher than a year earlier. Foreign receipts into Quebec and Ontario averaged 27 600 m^3/d and 1 600 m^3/d, down 10% and 40% respectively.

Figure 5.2.2
Crudes Oil Imports by Region

000 m^3/d

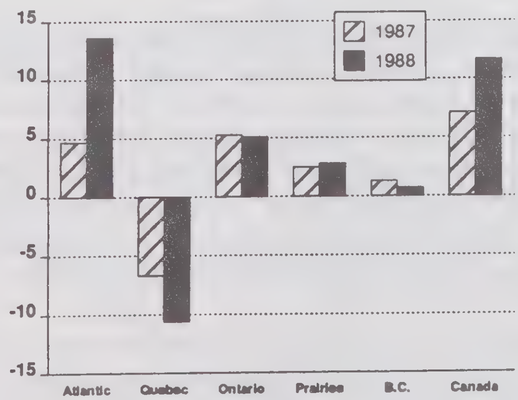


5.3 Petroleum Product Trade

Canada's net product exports reached 12 000 m3/d during the third quarter, almost 5 000 m^3/d higher than for the same period in 1987, but 10 000 m^3/d less than the second quarter balance. (A drop in exports from the Atlantic coupled with an increase in imports for Quebec resulted in the lower quarter-over-quarter net balance.)

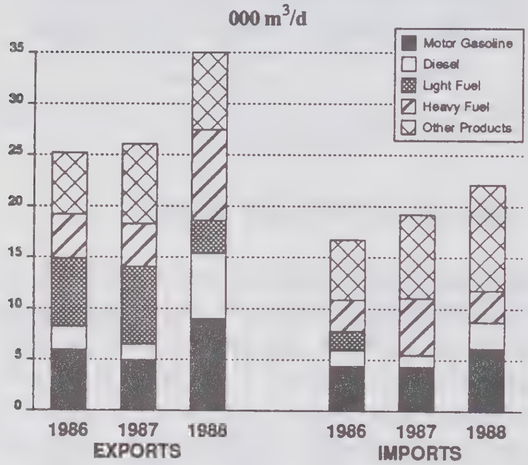
Figure 5.3.1
Net Petroleum Product Trade
(Third Quarter)

000 m^3/d



On a net basis, a year-over-year improvement of 9 000 m^3/d in the Atlantic, to over 13 000 m^3/d more than offset the change in Quebec (4 000 m^3/d). The Atlantic exports, mostly under processing agreements, reached 18 000 m^3/d, double the volume of 1987. In Quebec, the continued high demand for products resulted in a 4 000 m^3/d increase in imports for a third quarter net import position of 10 000 m^3/d. (Some of the receipts were added to inventories).

Figure 5.3.2
Gross Product Exports/Imports



Gross petroleum product exports totalled 35 000 m^3/d with motor gasoline and heavy fuel oil each accounting for 25% of the total. Most of the increases occurred in the Atlantic region. Motor gasoline exports from the Atlantic accounted for 60% of the total volume of gasoline exported from Canada.

Heavy fuel oil, also at 9 000 m^3/d was supplied mostly from the Atlantic, although exports from Ontario increased slightly to over 2 000 m^3/d. There was a slight drop from Quebec. Light fuel oil exports dropped from 8 000 m^3/d in the third quarter of 1987 to about 3 000 m^3/d in 1988. Exports of other products were slightly lower than in 1987 at 7 500 m^3/d, representing 21% of exports versus 30% a year earlier.

Sales to the United States accounted for virtually all of the exports with only a few cargoes sent elsewhere. PAD District I accounted for 60% of the U.S. total for main petroleum product exports, the same share as in 1987. (Refined products produced at the Come-by-Chance refinery are almost totally exported under a processing agreement, as are some other exports from the Atlantic region.) Main product exports from British Columbia to PAD District V increased 50% to 3 500 m^3/d of which over half was motor gasoline.

Gross petroleum product imports averaged 22 500 m^3/d during the third quarter, 3 000 m^3/d higher than a year before. The largest change occurred in Quebec, where imports increased 37% to 13 500 m^3/d. Ontario foreign product receipts dropped almost 50% to 1 500 m^3/d while B.C. imports doubled to 2 500 m^3/d.

The major changes by product category were for motor gasoline, which increased 40% to 6 000 m3/d and a jump of 2 000 m^3/d to 10 000 m^3/d for 'other products'. The latter category continues to account for about 45% of all imports.

While international trade of petroleum products serves to balance refinery output to demand and inventories, interregional trade also plays an important role in meeting these needs.

Interestingly, over the last seven years the total volume delivered or received from each region has been relatively stable, although the volumes relating to specific regions has changed.

Table 5.3.1
Interprovincial Petroleum Product Trade

Year	Volume (m^3/d)	Share of Crude Runs
1982	35 800	15
1983	45 400	19
1984	37 000	19
1985	45 000	19
1986	47 800	21
1987	48 000	20
1988*	47 000	19

** first nine months of year*

Product trade, whether east-west or north-south, is necessary in terms of economy and efficiency to meet fluctuations in demand. Despite the complexity of refinery configurations, it is nearly impossible for any one refinery to efficiently supply all products, given seasonal fluctuations in demand, inter-fuel competition, shifts in consumer preferences and technological change. In certain markets and seasons, high demand for one product may create surpluses of other joint products. By transferring products, regional surpluses/shortages for products can be balanced in a cost effective manner. Moreover, excess production from a refining area can sometimes be marketed with higher profit margins in a neighboring province or state than internally, strictly based on distance. For example, northwestern Ontario can often be served more economically from Manitoba or Michigan than from southern Ontario.

Other forms of product transfers occur through paper transactions rather than by the physical movement of products as described above. These arrangements, which are becoming more prevalent as refiners expand their sales in areas where they do not have a refinery, take form either through direct purchase or exchange of products. This action is typically more cost-effective than physically transporting products between regions, increases refinery utization and results in increased competition and lower prices for the consumer than might otherwise be the case.

Figure 5.3.3
Net Regional Product Trade
Foreign and Domestic

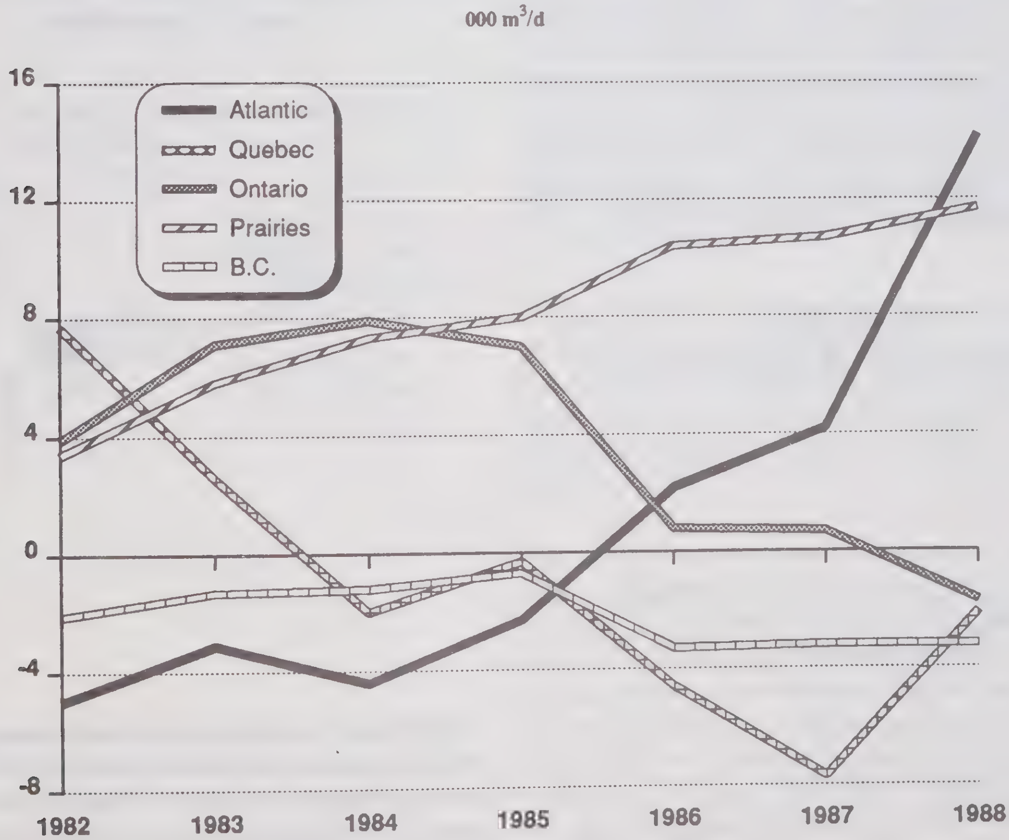


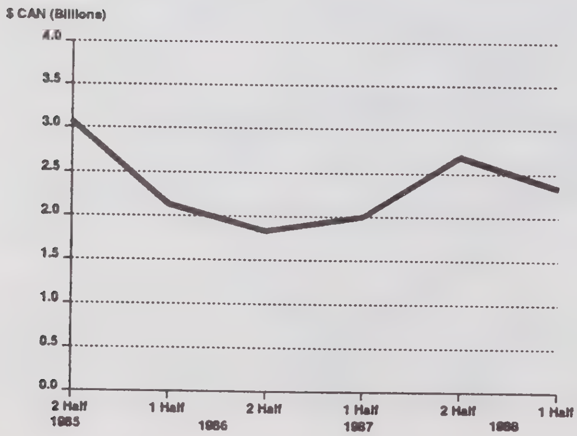
Figure 5.3.3 illustrates net regional product trade, including both international and interregional movements. Throughout the 1980s there have been a variety of factors (as mentioned above) and international market developments which have influenced interregional/international product movements. Two of the most significant, of course, were deregulation in Canada and the low and volatile prices of the last 3 years.

Often interregional and international product movements have been offsetting. For example, although Quebec is a net importer of petroleum products with respect to international trade, it is a "net exporter" on an interregional basis. The opposite is the case in Ontario.

5.4 Major Factors Affecting Oil Producers' Export Revenues

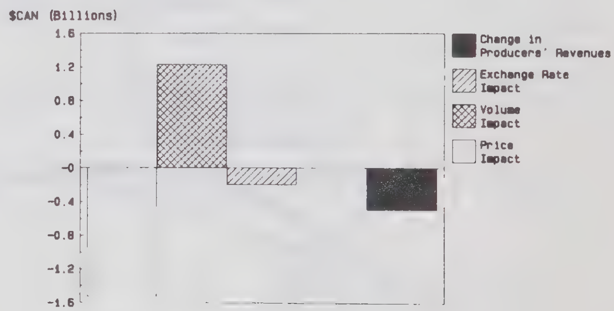
As shown in figure 5.4.1 Canadian crude oil producers have experienced an overall decline in gross crude oil export revenues since price deregulation came into effect in June, 1985. Nevertheless, the decline has not been a steady one. Gross export revenues increased immediately after deregulation by over 8% in the second half of 1985, and then againin 1987, following a dramatic drop in 1986, when they recovered and approached their pre-deregulation level, before resuming their downward course in the first half of 1988.

Figure 5.4.1
Producers' Crude Oil Export Revenues



To better understand the fluctuations in export earnings that have occurred over this period, it is revealing to look at the corresponding changes that have taken place in the individual components that make up gross revenues. By definition, export revenues (in Canadian dollars) accruing to producers are simply a product of the volume of exports, the U.S. price (as crude exports are denominated in U.S. dollars) and the prevailing exchange rate between the two countries' currencies. A change in the magnitude of any one of these three variables will produce a proportional change in export earnings. Disaggregating changes in producers' revenues on the basis of the above variables, therefore, permits a better insight into the factors that have led to the decline in export revenues. These components are shown in Figure 5.4.2 which illustrates, in dollars terms, the overall impacts of changes in price*, volume and exchange rate on producers' export earnings over the three year period since deregulation.

Figure 5.4.2
Overall Impact of Changes in Price, Volume and Exchange Rate



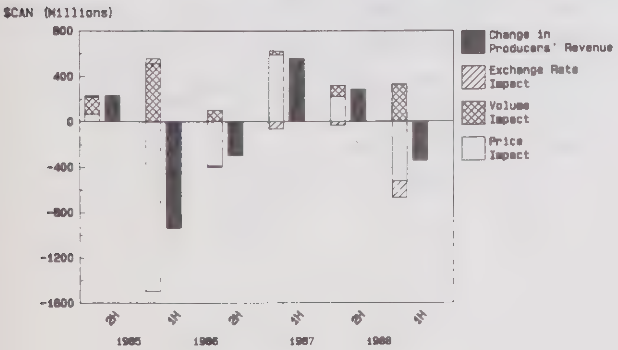
**Prices in the analysis are a weighted average of heavy and light crude export prices. Therefore their average level will be to some extent influenced by the change in the relative proportion of heavy and light crude exports.*

Export revenues were approximately $500 million lower in the first half of 1988 vis-à-vis the first half of 1985, the last period in which regulation was still in effect. Both the decline in export prices and, to a lesser extent, the rising value of the Canadian dollar contributed to the fall in earnings. These negative impacts, however, were largely offset by the increase in the volume of exports over the period. Had export volumes not increased, semi-annual earnings would have been significantly lower, i.e. by about $1.7 billion.

Looking at the overall picture however, conceals the significant swings in exports earnings and associated variables, which in fact occurred over the three-year period.

In a slightly different configuration, Fig. 5.4.3 illustrates the evolution of semi-annual changes in export revenues since the first half of 1985, along with the respective dollar contributions of price,volume and exchange rate variations to these changes. The following is a brief account of the ups and downs in producers' export revenues since deregulation.

Figure 5.4.3
Overall Impact of Changes in Price, Volume and Exchange Rate
(Semi-Annual)



Following deregulation, export revenues rose by approximately $240 million to $3.1 billion in the second half of 1985, compared with the first half. This increase was primarily attributable to higher export volumes in conjunction with higher crude prices in this period. Although also positive, the impact of the exchange rate on revenues, caused by a slight rise in the U.S. dollar, was minimal.

The post-deregulation prosperity proved to be short-lived. Export revenues plunged dramatically in the first half of 1986 following the crash in global oil prices brought on by OPEC overproduction. By itself, the price impact would have slashed producers' revenues in half; however, the combination of deregulation, the increase in crude supply coming on stream from previous exploration and development and from less restrictive provincial prorationing, and the positive effects of lower oil prices on exports, produced higher export volumes which partially offset the decline in price. The net effect was a drop in producers' revenues of $940 million, or 30%, to $2.1 billion in this period. Crude prices and revenues continued to fall, albeit somewhat less dramatically, in the second half of 1986.

The situation began to improve for producers in the first half of 1987. OPEC succeeded in restricting oil production, causing crude prices to rise. Moreover, although only slightly, export volumes continued to increase. The combination of higher prices and exports resulted in gross export earnings of almost $2.4 billion, a $562 million increase from the latter half of 1986. The increase would have been over 10% higher were it not for the appreciation of the Canadian dollar that occurred during this period which impacted negatively on earnings.

The latter half of 1987 saw prices and volumes continue to climb. Export revenues rose by $286 million to $2.7 billion, and approached their pre-deregulation level. Concurrently, the value of the U.S. dollar continued to fall, and this moderated somewhat the rise in export earnings.

After a year at relatively high levels, export prices began to decline in the first half of 1988. Moreover, the rate of appreciation of the Canadian dollar relative to the U.S. dollar accelerated. Both of these developments caused export revenues to decline by $350 million to $2.3 billion. Revenues would likely have been much lower had not the removal of major pipeline bottlenecks and increased crude supply added significantly to export movements.

It is interesting to note that despite international crude oil prices being cut by half over the last three years, Canadian producer revenues are only down about 18%, as the industry has managed to offset declining prices with rising sales. (In fact, the volume effect was positive throughout the three year period under consideration.) Whether it will continue to be able to do this in the future is another question.

6. Energy Trade Balance

- *The contribution of oil to the overall energy trade balance has declined.*

6.1 International

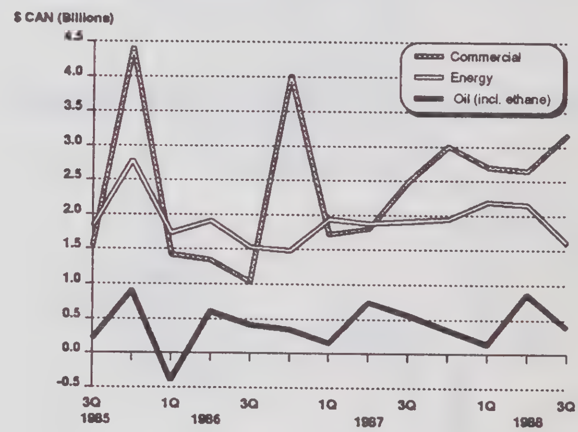
According to preliminary data from Statistics Canada, the Canadian energy trade surplus in the third quarter of 1988 was estimated at $1.6 billion, a drop of about $400 million from both a year ago, and from the second quarter 1988. In the third quarter of 1987, crude and products accounted for 28% or $550 million of the energy surplus, whereas in 1988 a $400 million oil surplus represented 24% of the energy surplus. As there was an increase in volumetric terms, the decline in the crude oil and petroleum products trade surplus was the result of the drop in oil prices, coupled with the stronger Canadian dollar vis à vis the U.S. dollar.

Natural gas contributed over $600 million to the trade surplus, almost $100 million more than in 1987, and was the only commodity to show any growth. Exports were 25% higher which helped offset lower prices. Despite an increase in net LPG exports, primarily because of a reduction in imports, lower prices resulted in the net trade in this area dropping nearly 50% to under $100 million.

Electricity exports contributed to a surplus of almost $300 million, however, this was about $75 million less than in 1987. Lower exports to the United States combined with higher imports from the United States, especially in July and early August, which were required to meet domestic needs during a long heat wave in eastern Canada, reduced the net balance.

As a result of both an improvement in the commercial trade surplus and deterioration in the oil balance, oil accounted for only 12% of the commercial surplus, compared with 20% in 1987.

Figure 6.1.1
Oil and Energy Trade Balance



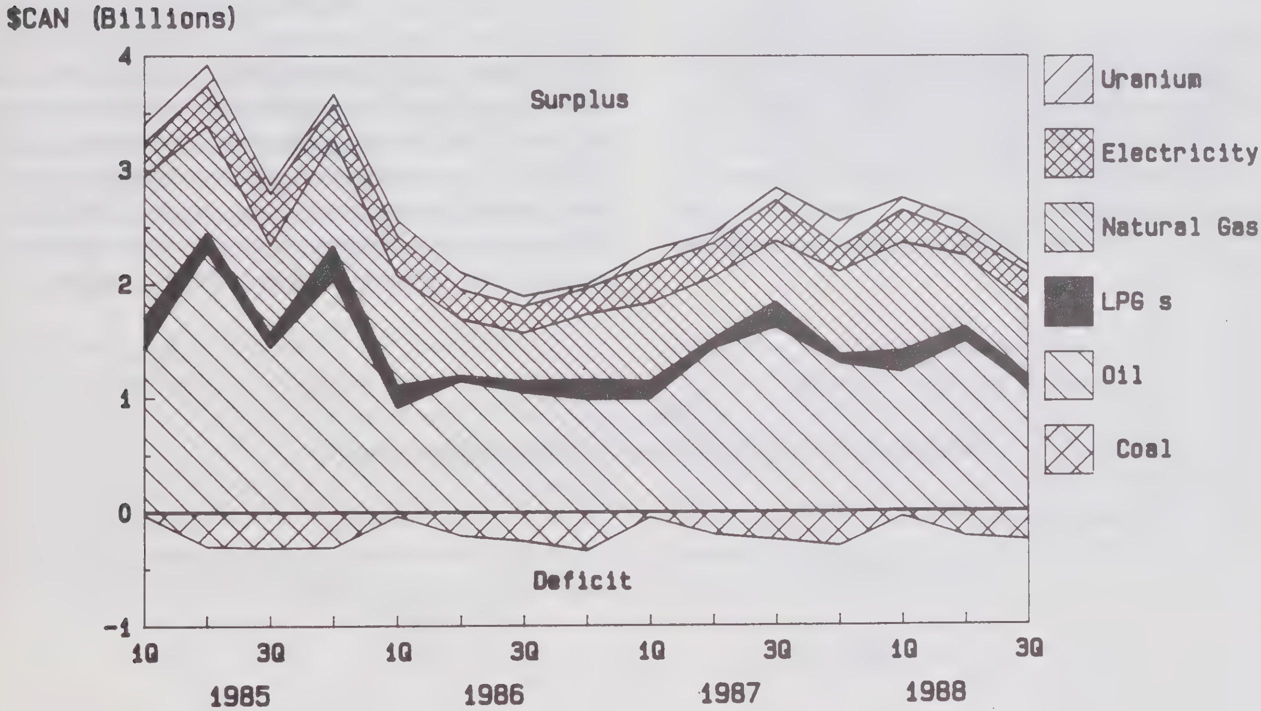
6.2 United States

Canada's energy trade surplus with the United States was almost $2 billion, a drop of more than half a billion from the third quarter of 1987. Almost all of the difference was accounted for by lower prices for crude oil and LPGs. The volume of crude exports was higher but lower prices and the increased strength of the Canadian dollar (up 8%) versus its American counterpart offset the volumetric gain. Nonetheless, crude oil and petroleum products still accounted for over half of the trade surplus with the U.S.

As mentioned in section 6.1 the natural gas surplus continued to improve, (all Canadian gas trade is with the United States) accounting for more than 30% of the energy surplus, up from 21% in 1987.

Following the seasonal pattern the coal deficit widened to more than $250 million.

Figure 6.2.1
Net Energy Commodity Trade with the U.S. (Value)



7. Stocks

- *Overall inventory levels in Canada up 3% from last year with refined product stocks higher in all regions of the country.*

Crude and petroleum product stocks at the end of the third quarter were 14.7 million cubic metres, up 3% from a year ago. During the month of September, there was a build of approximately 10 000 m^3/d. Petroleum products stocks, which represent over 80% of total stocks, accounted for all the volumetric increase, up 4% to 11.9 million cubic metres. Crude oil inventories fell by 1%, during the quarter to 2.8 million cubic metres.

Among products, heavy fuel oil and diesel showed the most significant increases, up 24% and 17%, respectively. These increases may reflect the upward trend in consumption and/or delays in purchase by final consumers in anticipation of lower prices as a result of declines in crude oil prices. These increases were partly offset by marginal declines in motor gasoline and light fuel oil.

As of October 1, 1988, the ratio of stocks to consumption (petroleum products and crude oil) was about 64 days of consumption, up 2 days from October 1987, and by 4 days from the end of the previous quarter. After three consecutive quarters of rising stock levels in 1987, in both absolute and relative terms, stocks have stabilized in 1988. Refiners and marketers have also shifted individual product levels somewhat, possibly reflecting the continued strong growth in heavy fuel oil and diesel demand relative to other products. As well, during the last half of 1987 there was a one-time inventory build concomitant with the reactivation of the Newfoundland refinery.

The inventories referred to above do not include crude oil in pipeline tankage. Including those stocks, the ratio of stocks to consumption would increase by about 7 days to 71 days. This level compares with the Organization for Economic Cooperation and Development (OECD) estimated average for the end of the quarter, of 69 days, which represents the lowest level since 1985. If government stocks were included the OECD number would rise by 28 days to 97 days. The current government ratio is the highest since 1976 when some governments, most notably the U.S. government, began purchasing crude for storage.

Figure 7.1.1
Closing Crude and Product Inventories in Canada

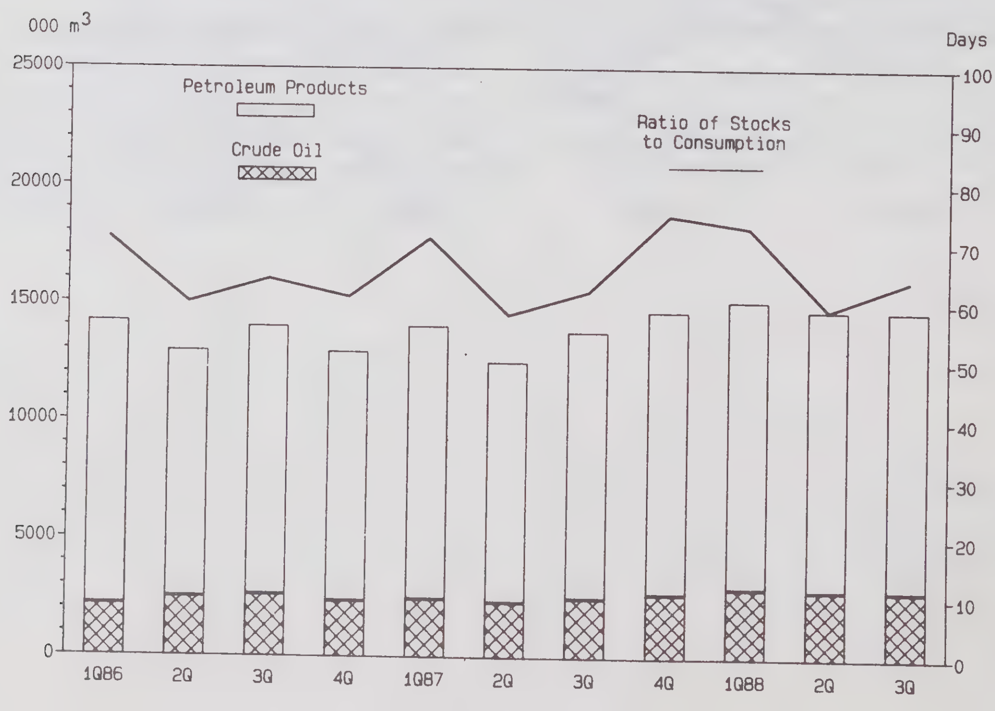


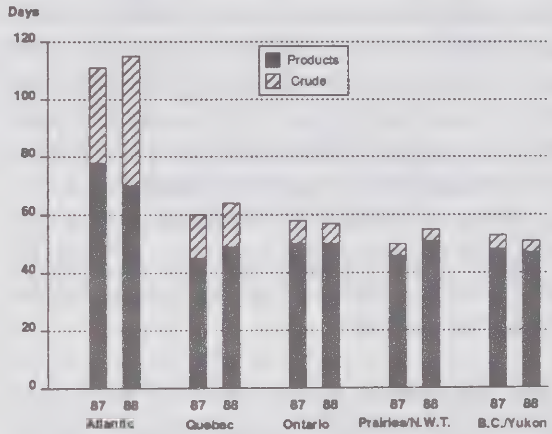
Table 7.1.1
Closing Inventories by Region
- September

	1987		1988	
	Crude	Product	Crude	Product
	(000 m3)			
Atlantic	800	1920	1249	1929
Quebec	792	2335	718	2430
Ontario	588	3644	530	3834
Prairies	178	2280	218	2489
B.C.	113	1132	100	1198
Canada	2471	11311	2815	11880

On a regional basis, the year-over-year increase in total crude oil inventories mainly occurred in the Atlantic region, up 56%, largely as a result of the Come-by-Chance refinery which came on stream last fall, and of fluctuations in the delivery system (tanker versus pipeline). With the exception of the Prairies, up 22%, all other remaining regions recorded declines.

Petroleum product inventories increased in all regions, ranging from less than 1% in the Atlantic region to 9% in the Prairies. Most of the increase in the Prairies occurred in diesel fuel, up 26%, and "other products" which more than doubled to 614 000 cubic metres. The increases in the Prairies, in part, are the result of higher petroleum product demand in the Prairies, and increased shipments to British Columbia. In Quebec, petroleum product sales and crude run to stills declined, while the net petroleum product import trade balance surged by almost 4 000 m^3/d. A portion of this increase went into inventory.

Figure 7.1.2
Ratio of Stocks to Consumption
End September



Reflecting its reliance on imported crude, the Atlantic region continued to maintain the highest level of inventories relative to consumption, reaching 115 days (of which 70 days represent petroleum products), up 4 days from a year ago. Quebec and the Prairies also recorded relatively high increases, 4 days and 5 days respectively, and both were derived from higher petroleum product inventories.

8. Prices

- *Prices for both crude oil and refined products fell throughout the third quarter, reflecting international developments.*

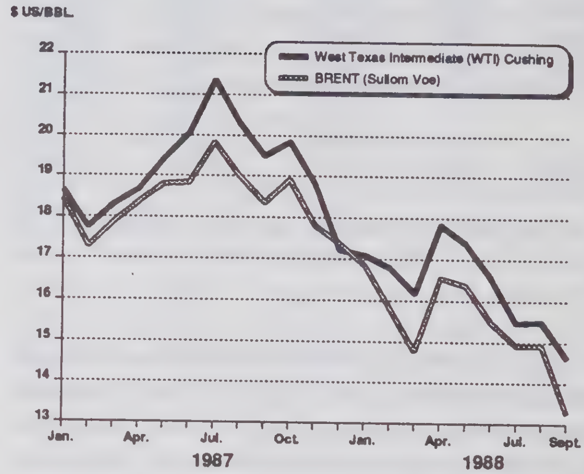
8.1 International Crude Oil Prices

Spot crude oil prices declined through the third quarter of 1988 as bearish sentiment, brought about by steadily rising OPEC crude oil production, pervaded world markets. In July, compared with the previous month, spot West Texas Intermediate (WTI) prices fell over a $1/bbl, to $15.45/bbl. This was in part a reflection of OPEC's inconclusive mid-year ministerial conference. Only the Piper Alpha rig disaster in the U.K. North Sea and Iranian acceptance of the U.N. Security Council ceasefire resolution caused prices to momentarily halt their descent.

In August, OPEC managed to stabilize prices through a series of meeting announcements, leading to a Price Monitoring Committee (PMC) meeting, and by outlining possible advantages of greater OPEC cohesion gained by the announcement of an Iran/Iraq official ceasefire on August 20. The PMC meeting failed to offset the impact of rising OPEC crude oil output, however which exceeded 19 MMB/D in August, and crude prices remained weak, with WTI averaging $15.50/bbl and U.K. Brent $14.90/bbl.

By September OPEC was in the midst of a virtual price war over market share with many members, led by Saudi Arabia, exceeding production quotas. Hurricane Gilbert briefly interrupted oil operations in Mexico and the U.S. Gulf Coast region causing a pause in the price decline. Because excess OPEC production continued to swell world oil inventories and crude oil price discounting was common practice, prices began to fall once again. Another inconclusive OPEC PMC meeting contributed to a late-month price fall with WTI reaching a two year low of $13.35/bbl. With OPEC crude oil production exceeding 20 MMB/D, the spot WTI average price in September fell to $14.65/bbl while Brent fell to $13.25/bbl.

Figure 8.1.1
Spot Crude Oil Prices



8.2 Domestic Crude Oil Prices

Light Canadian crude oil posted prices during the third quarter 1988 averaged $CDN 17.72 per barrel, a decrease of $2.66 from the second quarter. The decrease in crude oil prices is primarily attributed to a world oil price decrease equivalent to about $CDN 2.50 per barrel. The strengthening of the Canadian dollar vis-à-vis the American dollar had an additional downward influence of about $0.16 per barrel on Canadian crude oil prices.

Canadian light crude oil prices follow the trend set by international crudes, primarily the U.S. benchmark crude West Texas Intermediate (WTI). The following figure illustrates the close relationship between prices for WTI and Canadian crudes, after adjustments for delivery times to Chicago.

Figure 8.2.1
Canadian Par Crude vs WTI (NYMEX)

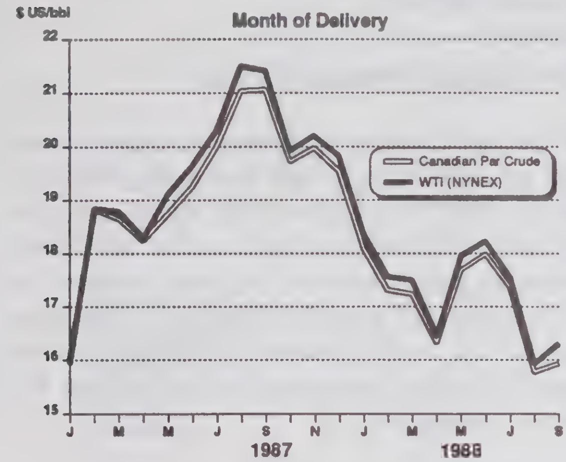
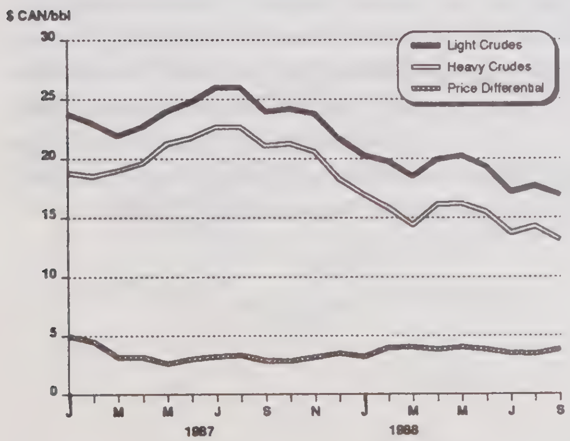


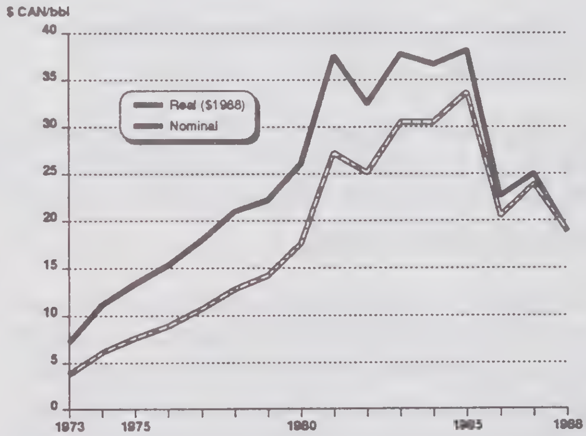
Figure 8.2.2 compares actual prices for Alberta light crude and heavy crude oil, purchased for use in Canada at main trunk line injection stations. The differential between Canadian light and heavy crude prices, for the third quarter, was about \$3.56 per barrel, almost \$0.50 lower than the second quarter differential but \$0.44 per barrel higher than during the third quarter of 1987. The differential typically narrows in the summer reflecting higher demand for heavy Canadian crudes during the asphalt season. There appears to have been less of an impact this year which may reflect a longer term widening of differentials.

Figure 8.2.2
Comparison of Domestic Light and Heavy Crudes
(Actual Purchase Price)



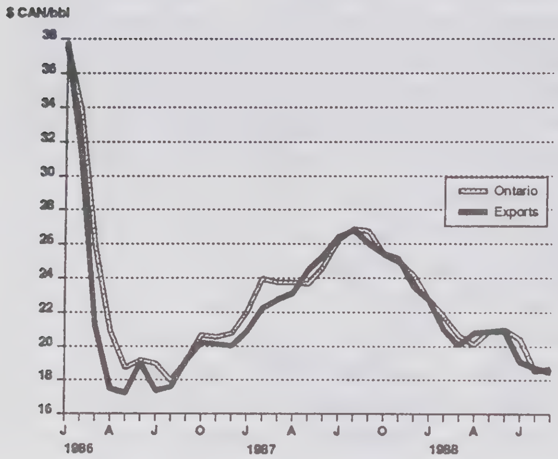
As indicated in Figure 8.2.3 Canadian light crude oil prices are estimated to average \$19/bbl over the first three quarters of 1988 which is the equivalent price level, in real terms, to the 1977 average wellhead price received by Canadian producers. While international prices peaked in 1981 at \$44/bbl, reflecting the beginning of the Iran/Iraq war, Canadian prices, which were regulated over most of this period, peaked four years later in 1985, at about \$38/bbl (1988). Since then Canadian prices have generally tracked the decline in world oil prices.

Figure 8.2.3
Canadian Average Light Wellhead Crude Oil Prices



Even though Canadian light crude prices are back at 1977 levels in real terms, producers' gross revenues will still be higher in 1988, because production is expected to be 10% greater than in 1977. This does not, however, indicate that producers are still better off than in 1977. Producer netbacks (real) which take into consideration changes in operating costs and fiscal and tax regimes, would have to be compared in the two periods.

Figure 8.3.1
Domestic Light Crude Export and Ontario Domestic Acquisition Values



8.3 Light Crude Value: Export Versus Domestic

The average value of Canadian light crude exported during the third quarter was around $18.75/bbl, $0.50/bbl lower than the same quality of crude delivered to Ontario refiners.

The widest gap between the two destinations was recorded in July (at $1.35/bbl), the result of a drastic change in international prices following an inconclusive OPEC meeting and world oil overproduction. Both domestic and export prices fell in July, but the decline was felt more rapidly in export market sales because of the shorter delivery distance. In August and September, prices in both the domestic and export market were more stable, fluctuating between $18.50 and $18.75/bbl, with an end-September export price of $18.50/bbl, $0.25/bbl below the Ontario deliveries.

IPL pipeline constraints may have contributed to some export discounting in July as a result of some uncertainty of supply but the situation returned to a normal pricing relationship in August and September.

8.4 Petroleum Product Prices

Retail prices of regular unleaded gasoline fell an average of almost 2 cents per litre during the third quarter of 1988. Price declines were recorded in nine of the eleven cities surveyed and ranged from 0.9 to 6.2 cents per litre. Price war activity, prevalent in several central and western Canadian cities, contributed to the larger declines; however, prices increased 0.2 and 4.0 cents per litre in Winnipeg and Vancouver, respectively.

Retail diesel prices fell an average 0.1 cents per litre during the third quarter, to 47.6 cents per litre. Diesel prices ranged from 39.9 cents per litre in Calgary to 57 cents per litre in St. John's, Nfld.

There were several changes to federal and provincial gasoline and diesel consumption taxes during the third quarter of 1988 (see Appendix II). On July 1, 1988, the federal sales tax was increased 0.01 cents per litre on gasoline and decreased the same amount on diesel.

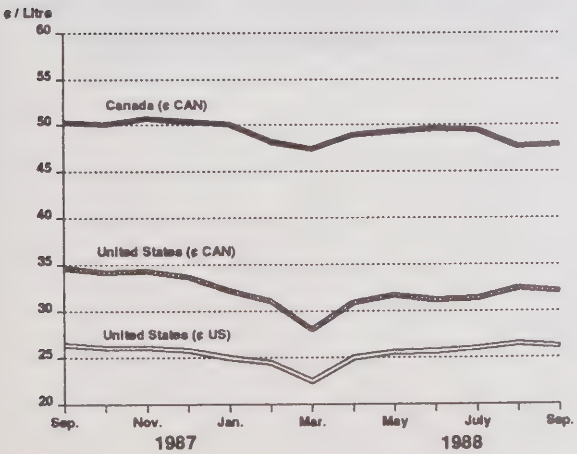
Combined federal sales and excise taxes on regular unleaded gasoline in September of 1988 accounted for 20.5% of the pump price, as compared with 19.7% in June. The federal sales tax on gasoline is based on a 12% ad valorem rate and is adjusted quarterly to reflect changes in a twelve-month average industrial product price index for gasoline, with a one-quarter lag.

The five provinces with ad valorem tax rates made adjustments to their taxes. The only significant change was in British Columbia where the effect of the April 1, 1988 increase of 2.5% in the ad volorem rate resulted in a 0.7 cent per litre increase in gasoline and diesel taxes on July 1. In Manitoba the surtax on regular leaded gasoline was increased from 0.9 cents per litre to 1.8 cents per litre as announced in a budget.

Table 8.4.1
Average Regular Unleaded Gasoline Prices
Full-Serve and Self-Serve
1987-1988

	1987 Dec	1988 March	1988 June	1988 Sept.	% Change Last 12 months
St.John's (Nfld.)	55.5	55.2	54.8	53.7	3.4
Charlottetown	53.3	53.4	52.7	51.5	-3.4
Halifax	51.5	50.8	51.0	49.7	1.6
Saint John (N.B.)	50.7	49.6	50.9	50.0	2.7
Montreal	57.9	56.9	57.4	56.2	-2.8
Ottawa	51.8	51.4	51.8	50.2	-3.3
Toronto	49.4	46.5	49.9	46.6	-7.9
Winnipeg	47.8	43.9	46.1	46.3	-3.7
Regina	50.3	48.2	46.7	40.5	-13.1
Calgary	47.2	38.1	43.5	41.6	-5.9
Vancouver	51.2	48.5	44.9	48.9	-7.4
Canadian average	51.4	48.4	50.3	48.5	-5.6
Consumption taxes included:					
Federal	8.79	8.86	9.93	9.94	13.1
Provincial	9.45	9.41	9.82	9.87	4.7

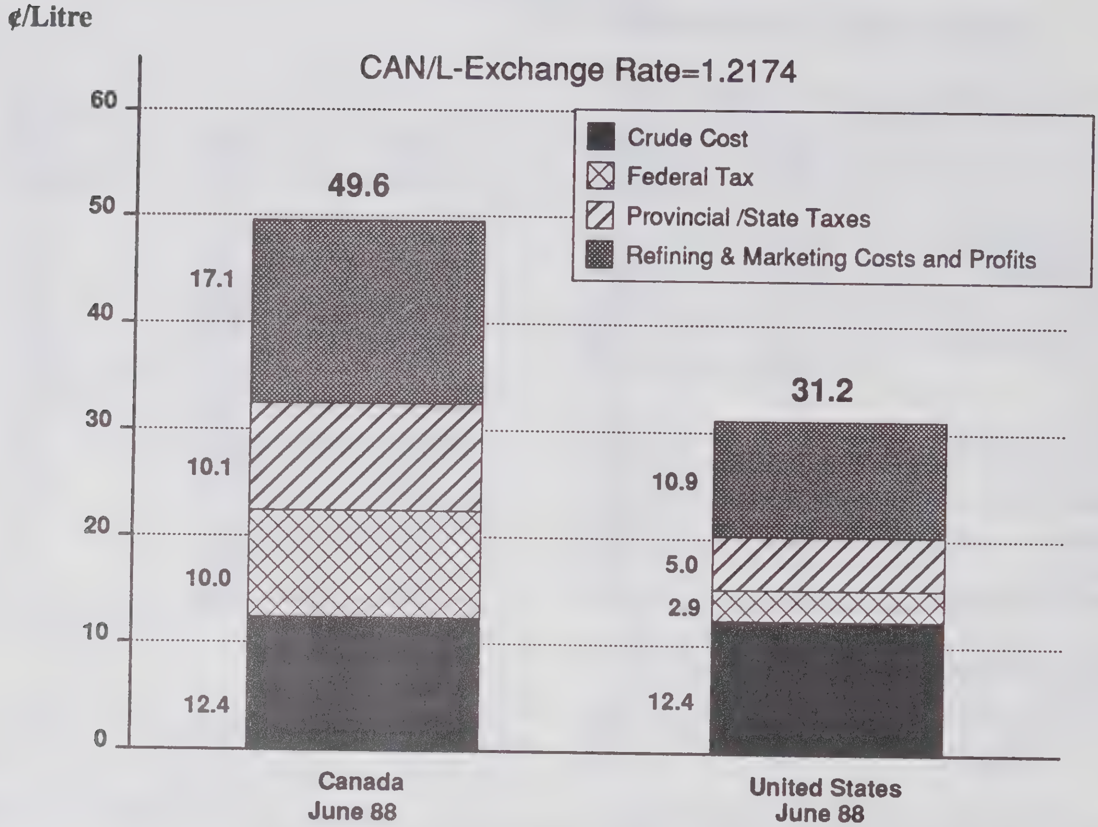
Figure 8.4.1
Average Retail Price of Motor Gasoline
Canada vs United States



Figures 8.4.1 and 8.4.2 compare average gasoline prices in Canada and the United States. The average pump price in Canada fell 1.7 cents per litre while in the United States it increased 0.9 cents per litre (in Canadian currency) during the third quarter of 1988.

The bar charts illustrates the components of the average pump price in each country using September 1988 data. Crude costs are the average refinery acquisition cost (cost of crude received at the refinery gate) lagged by 60 days in Canada and 45 days in the United States. The refining and marketing costs and profits component is the residual revenue available to cover refining, marketing and disposition costs, and to provide a return to the industry on its investment after crude oil costs and taxes are removed.

Figure 8.4.2
Breakdown of Average Pump Price
(September 1988)



Gasoline prices in Canada in September of 1988 were 15.8 cents per litre higher than in the United States. This reflects a narrowing in the differential during the last quarter, of 2.6 cents per litre. About three-quarters of the differential in September was accounted for by higher taxes in Canada (12.2 cents per litre). The balance is attributable to higher refining and marketing costs and/or profits in Canada. The larger refining and marketing costs and profits component in Canada results from structural differences between the two markets e.g. economies of scale in the form of substantially higher volume per unit of investment which favour U.S. refiners, marketers and consumers.

9. Drilling Rig Activity

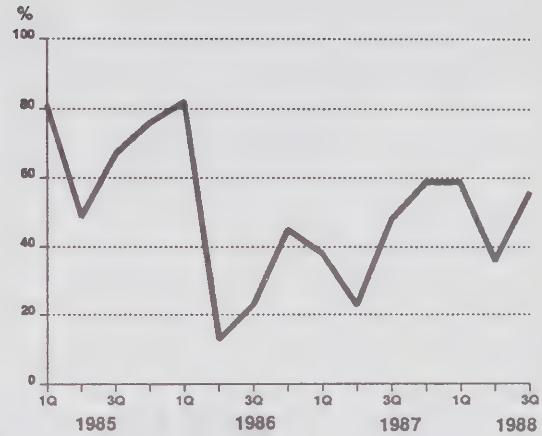
- *A spurt of activity for drilling rigs during the third quarter may have been in anticipation of a scaling down of government support measures.*

Drilling rig activity during the third quarter 1988 averaged 316 active rigs, representing a utilization rate of 56%, up 8 percentage points from a year ago. There were 15 additional rigs (for a total of 566) available for work in the third quarter. The number of active rigs rose gradually throughout the quarter, from 270 rigs in July to 357 in September. This increase reflected the approaching federal Canadian Exploration and Development Incentive Program (CEDIP) deadline to decrease (on September 30) the rebate on drilling expenditures from 33.3% to 16.66%. Most of the increase occurred in Alberta, up 39% to 230 active rigs. Saskatchewan also felt some positive effects from the approaching federal deadline. In response to falling oil prices and industry concerns, the federal government announced that CEDIP grants for oil and gas exploration and development drilling would be extended at 25% of expenditures until June 1989.

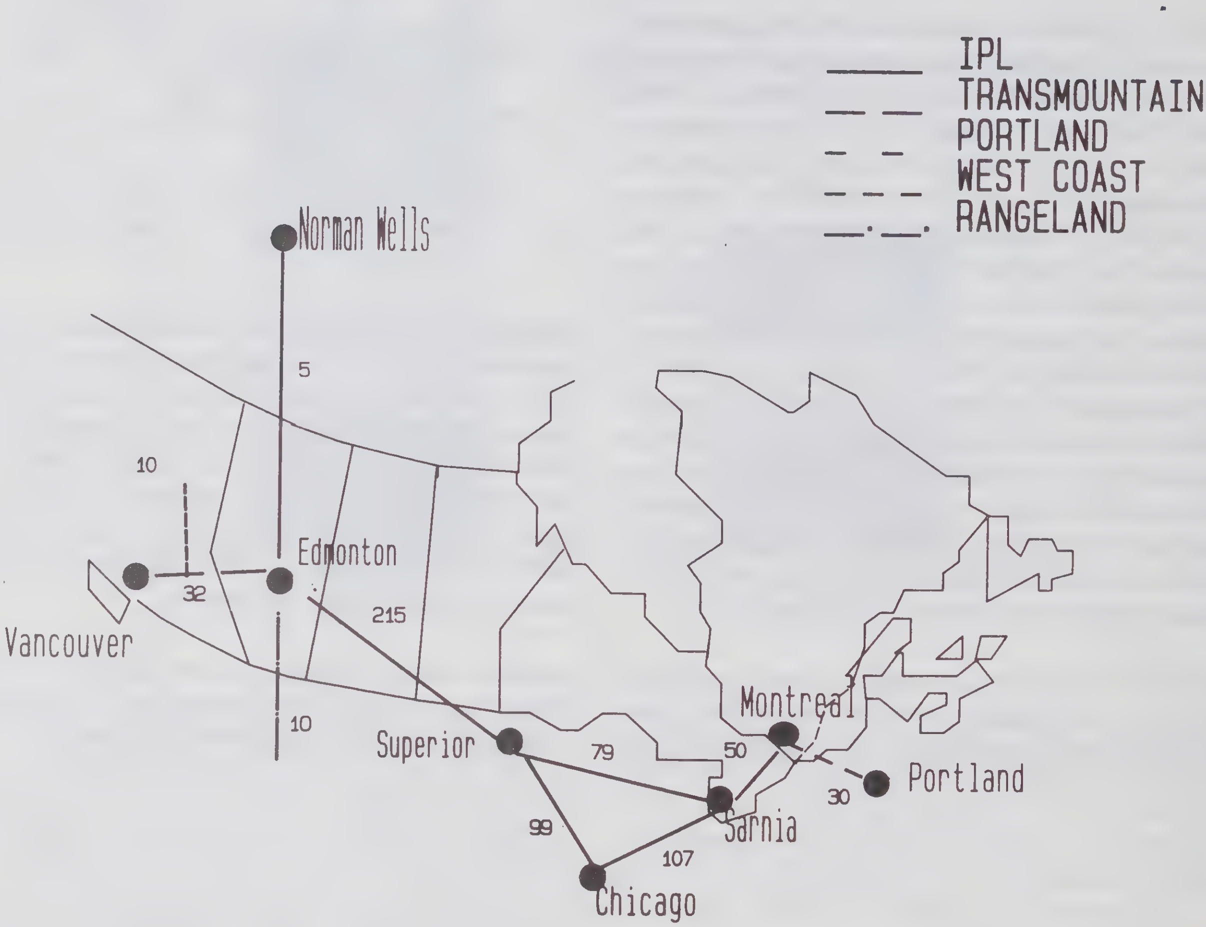
In addition, the Alberta government has extended two tax breaks, the Alberta Royalty Tax Credit (ARTC) and the three-year royalty holiday. The extension of these programs will enhance the cash flow and project economics for the conventional oil industry of Alberta by $150 million to $250 million depending on oil prices. The royalty holiday, which was expected to expire on November 1, will now be extended until April 30, 1989, to a maximum of $1 million per well. Also, the ARTC will remain in effect until the end of 1989, with a 75% rebate on provincial royalties to a maximum of $3 million per corporation.

Another factor contributing to the upswing in drilling activity was the search for natural gas in anticipation of stronger export markets for that commodity.

Figure 9.1.1
Drilling Rig Activity



Appendix I
Major Crude Oil Pipelines in Canada



Appendix II
U.S. Petroleum Administration for Defense (PAD) Districts

Appendix III
Consumption Taxes on Petroleum Products
(September 1, 1988)

	Ad valorem		Gasoline			
	Mogas	Diesel	Reg L	Reg UL	Prem UL	Diesel
	(%)			(cents per litre)		
FEDERAL TAXES						
Sales			3.44*	3.44*	3.54*	2.64*
Excise			6.5	6.5	6.5	4.0
PROVINCIAL TAXES						
Newfoundland	22	26	9.6*	9.6*	9.6*	11.5*
Prince Edward Island	20	23	8.5*	8.5*	8.5*	8.8*
Nova Scotia	20	21	8.4*	8.4*	8.4*	8.8*
New Brunwwick	20	23	8.1*	8.5*	9.0*	8.2*
Quebec			14.4	14.4	14.4	12.45
Ontario			12.3	9.3	9.3	9.9
Manitoba			9.8*	8.0	8.0	9.9
Saskatchewan			7.0	7.0	7.0	7.0
Alberta			5.0	5.0	5.0	5.0
British Columbia	22.5(b)	22.5(b)	10.08*	8.08*	8.08	*8.52*
Yukon			4.2	4.2	4.2	5.2
Northwest Territories	17	(c)	8.4	8.4	8.4	7.1

(a) Reduced by varying amounts in certain remote areas and within 20 kilometres of the provincial and U.S. borders.

(b) Additional transit tax of 3.0 cents per litre in Vancouver.

(c) 85% of gasoline tax.

** Changed since last quarter.*

Glossary

Bitumen	A naturally occurring viscous mixture composed mainly of hydrocarbons heavier than pentane, which may contain sulphur compounds and which in its natural state is not recoverable at a commercial rate through a well.
Conventional areas	Those areas of Canada that have a long history of hydrocarbon production. Conventional areas are also referred to as nonfrontier areas.
Crude oil and equivalent	Includes crude oil, synthetic crude, oil produced from oil sands plants, and condensate.
Feedstock	Raw material supplied to a refinery or petrochemical plant.
Heavy crude oil	Loosely applied, crude oils with a low API gravity (high density).
In situ recovery	With reference to oil sands deposits, the use of techniques to recover bitumen without the necessity of mining the sands.
Light crude oil	Crude oil with a high API gravity (low density). Generally includes all crude oil and equivalent hydrocarbons not included under heavy crude oil.
Natural gas liquids	Those hydrocarbon components recovered from raw natural gas as liquids by processing through extraction plants, or recovered from field separations, scrubbers or other gathering facilities. Includes the hydrocarbon components ethane, propane, butane and pentanes plus, or a combination thereof.
Oil sands	Deposits of sands and other rock aggregate that contain bitumen.
Pentanes plus	Also referred to as condensate. A volatile bydrocarbon liquid composed primarily of pentanes and heavier hydrocarbons. Generally a by-product obtained from the production and processing of natural gas.
Productive capacity	The estimated production level that could be achieved, unrestricted by demand, but restricted by reservoir performance, well density and well capacity, oil sands mining capacity, field processing and pipeline capacity.
Shut-in capacity	The unused production capability of currently producing oil and gas wells plus the total production capability of all shut-in oil and gas wells, whether or not they are connected to surface gathering and production facilities.
Synthetic crude oil	Crude oil produced through treatment of oil sands in upgrading facilities designed to reduce the viscosity and sulphur content.

Energy, Mines and Resources Canada
Énergie, Mines et Ressources Canada

The Canadian Oil Market

Vol. IV, No. 4, Fourth Quarter 1988

Canada

THE CANADIAN OIL MARKET

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Domestic Oil Division
Energy Sector
Energy, Mines and Resources Canada

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Table of Contents

Appendices

LIST OF FIGURES

Appendices

LIST OF TABLES

Appendices

THE CANADIAN OIL MARKET

OVERVIEW

- *A review of both the fourth quarter of 1988 and the highlights of the entire year, with emphasis on the latter, are included in this issue. Where appropriate, the outlook over the short-term is also discussed. In a departure from the standard format, a descriptive analysis of trends over the decade in the demand for "other products" (which now account for roughly one-fifth of all oil consumed in Canada) is incorporated in this issue (see section 1.4). Furthermore, two recently published long-term Canadian oil supply forecasts are summarized and compared (see section 4.4).*

- *Oil consumption in Canada in 1988 was up fairly sharply as compared to recent rates of growth but this experience is unlikely to extend into 1989 for several reasons. The growth was focused on the eastern half of the country.*

- *Refinery throughputs all across the country rose reflecting higher sales in Canada and abroad, yet, by the end of the year, inventories had fallen relative to a year earlier. As a result, refiners' crude oil demands are expected to remain strong in 1989.*

- *Crude oil prices fell throughout 1988, only to recover at the end to about the same level as one year earlier. Drilling activity tended to suffer as a consequence and is not likely to recover in 1989. Overall capital expenditures in the upstream oil and gas industry are expected to fall by about 10% in 1989, but this will be offset by roughly corresponding increases in spending on pipelines and refineries.*

- *All major oil pipeline systems out of Alberta were operating at or near capacity levels, despite additions to capacity over the past few years. Deliveries to both Canadian and export markets rose over the year, which when combined with a marginal decline in light crude oil productive capacity and a slow-down in the rate of growth in the case of heavy crude, yielded relatively minor shut-in productive capacity over the course of the year. Unless crude oil prices recover on a sustained basis, this situation is unlikely to change in 1989 as several possible projects have been delayed pending improved prices and some marginal wells have been shut down. Given the declining availability of U.S. light crude oil, a general tightening of the market for light crude oil can be expected in 1989 in the U.S. mid-west and in central Canada, resulting in higher imports into those regions.*

1. Domestic Demand

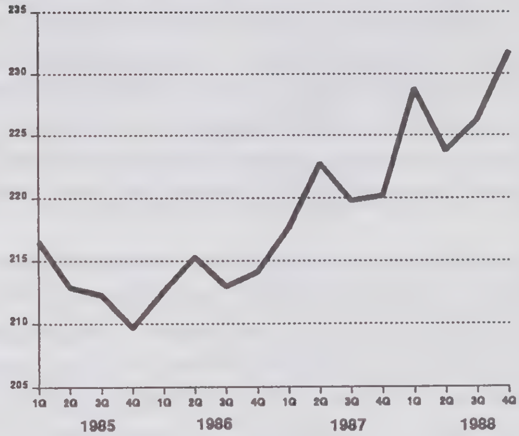
- *Growth in consumption of petroleum products in Canada was almost 4% in 1988 but appears to have slowed in latter part of the year*
- *Heavy fuel oil sales jumped sharply but unlikely to maintain strong growth*
- *Growth was strongest in Quebec and Atlantic Canada*

1.1 Seasonally Adjusted

Seasonally-adjusted petroleum product consumption in the fourth quarter of 1988 averaged 232 000 m^3/d, about 2% above the average for the year and 5% above sales in 1987. The first quarter spike and subsequent second quarter fall-off in sales was a reflection of end-consumers efforts to build inventories prior to the 1 April, 1988 increase in the excise tax on motor fuels. During the second half of the year, the rate of growth appears to have tapered off somewhat.

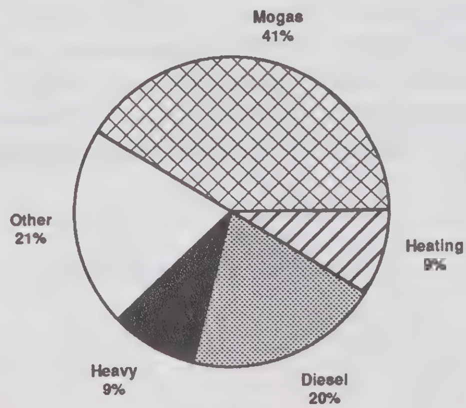
The increase in sales in 1988 continues the recovery trend which began late in 1985 following a substantial drop of 25% in petroleum product sales over the first half of the decade. The latter was the product of a combination of factors including an economic recession in the early 1980's, high crude oil prices, increased fuel efficiency and conservation, and government-supported fuel substitution away from oil products to natural gas and electricity. Since then the situation has improved considerably with regard to petroleum product sales opportunities. The economy has experienced uninterrupted growth of around 4% a year; the government has in the meantime reduced or eliminated certain "off-oil" incentives and in 1988 crude oil prices averaged about half of what they were in 1985.

Figure 1.1.1
Total Petroleum Product Consumption
(Seasonally-Adjusted)
000 m^3/d



On an annual basis consumption in 1988 was almost 228 000 m^3/d, an increase of 3.7% over 1987. All the "main" petroleum products recorded increases in sales. Motor gasoline, which represents about 41% of refined product demand increased by over 2% from last year, to 93 000 m^3/d. This increase is mainly attributable to lower gasoline prices in 1988 and the healthy state of the economy, particularly in eastern Canada. Growth in gasoline sales were fairly evenly distributed across all regions, with the exception of the Prairies where consumption remained flat.

Figure 1.1.2
Canadian Oil Product Sales
1988
% Share



For similar reasons, diesel fuel, with a 20% share of product sales, had an increase in sales of 6% to 46 000 m^3/d. Diesel fuel accounted for a third of the total increase in consumption of the main petroleum products. Sales growth was highest in Quebec at 11% reflecting the increasing strength of the economy in this region. As with motor gasoline, sales were unchanged in the Prairies, reflecting the economic problems this region faced in 1988. It is interesting to note that while motor gasoline sales have remained virtually flat since 1983, diesel fuel consumption has increased by about 20%.

Sales of heating oil were up 5% from last year to 20 500 m^3/d. On the one hand, this could reflect the fact that, on a degree day basis, 1988 was over 6% colder than 1987; and on the other, that there may have been an above-normal build-up of inventories (in part because of lower prices) by distributors and consumers in 1988. Nevertheless, heating oil sales are currently 25% below their 1984 levels largely as a result of fuel substitution and energy conservation; and now comprise only 9% of total product sales. Regionally, sales growth was highest in British Columbia and Ontario with increases of 13% and 8%, respectively.

Demand for heavy fuel oil continued its upward climb in 1988 reaching 21 500 m^3/d, a dramatic 14% increase from the previous year. Heavy fuel oil consumption has been increasing rather steadily since the second half of 1985. This upward trend has been accentuated in the last year or so by the strong demand for this product in the pulp and paper industries in Quebec and British Columbia, up 32 and 16% respectively. Moreover in light of increasing environmental concerns and its relatively low world price, heavy fuel oil is being substituted for coal in thermal electricity generation (most notably in the Atlantic region). The strength in Quebec also reflects some switching back to oil from electricity as some incentive pricing contracts of Hydro Quebec came to an end. The increase in Ontario, although more modest (12%), reflects some switching from natural gas and the re-activation of heavy fuel oil-fired electricity generation plants.

Table 1.1
Petroleum Product Consumption

	1987	1988	% Change
	000 m^3/d		
Atlantic	28.3	29.9	5.5
Quebec	46.9	50.5	7.6
Ontario	74.0	76.4	3.2
Prairies/NWT	46.0	45.9	-0.1
BC/Yukon	24.4	24.9	2.2
Canada	**219.6**	**227.7**	**3.7**

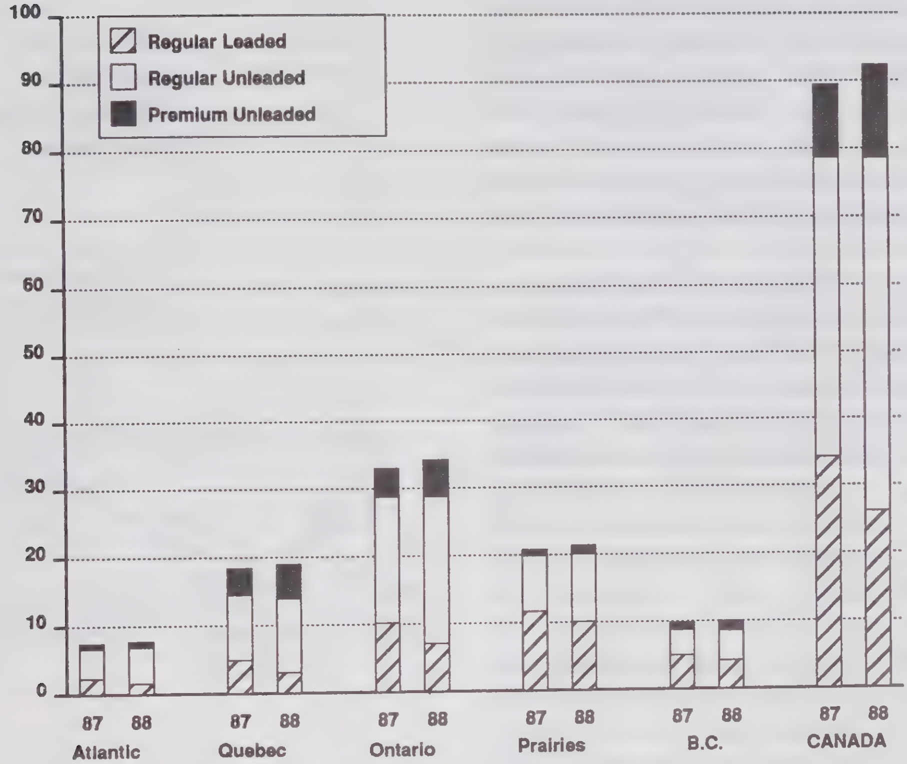
"Other products" was the only category of refined products to show a decline, however minimal, in sales from 1987. The fall in demand for both asphalt and petrochemical feedstocks, two important products in this category, led to this decline.

Overall product consumption was up in all regions with the exception of the Prairies whose economy was hit hard by both a drought and low oil prices in 1988, causing total product consumption in this region to remain virtually unchanged from the previous year. Growth in the other regions ranged from 2% in British Columbia to 8% in Quebec.

1.2 Motor Gasoline Sales

The general market shift from regular leaded gasoline continued throughout the year; however, the swing to unleaded fuel remained more pronounced in the eastern regions of the country. In 1988, regular unleaded accounted for 57% of gasoline sales, a 7% increase from 1987. After taking premium unleaded into account, only 28% of gasoline sales in Canada were leaded.

Figure 1.2
Total Gasoline Sales
(million litres per day)



1.3 International Oil Consumption

Canada's growth in consumption of refined products vis-à-vis other major industrialized countries was higher than either that of the United States or Europe but lower than that of the Pacific rim area. Canada's growth was largely attributable to increased consumption of middle distillates and heavy fuel oil. On the other hand, the low growth in Europe was largely the result of unseasonably mild weather in the first quarter of 1988 which reduced demand for both middle distillates and heavy fuel oil. The high growth rate in the Pacific rim reflected the strong economic performance there, particularly in Japan where consumption of middle distillates surged.

Table 1.3
Petroleum Product Consumption
% Change 1987/1988

Product	Canada	U.S.A.	OECD Europe	Pacific
Motor Gasoline	2.3	1.4	3.0	3.1
Middle Distillate	5.4	3.3	-1.3	11.3
Heavy Fuel Oil	14.4	--	-4.7	1.6
Other Products	-0.5	5.8	4.8	6.1
Total	**3.7**	**3.0**	**0.4**	**6.3**

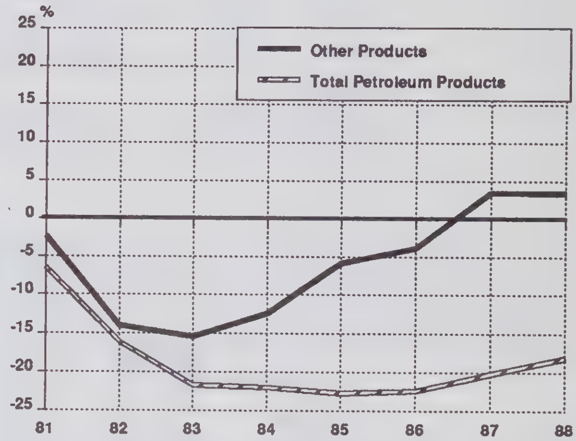
1.4 Review of "Other Products"

The category "Other Products" refers to a number of products that individually account for a small fraction of total petroleum product output and sales, yet collectively comprise more than 20% of total product supply (47 000 m^3/d in 1988). Their relatively small volumes often belie their importance to refinery profits and marketing strategies, and their value to society. In this section, the contribution of these products to total demand over the past decade will be reviewed.

Several "other products" can be identified. Statistics Canada's monthly "Refined Petroleum Products" (Cat. #45-004), distinguishes the following products: propane, butane, petrochemical feedstocks, naphtha specialties, aviation gasoline, jet fuel, petroleum coke, asphalt, lubricating oils and greases, still gas and a residual category made up of miscellaneous and partially processed products. Some of these products tend to be gases, others liquids and still others solids at ambient temperatures and pressures.

The physical properties themselves are important in the selection of the optimum refinery product mix, for they largely determine the relative values of the products through their impact on demand. No refined product is intrinsically more valuable than another. Rather it is to what uses the product can be put, which in turn depends on how it complements or can be exploited by the prevailing technologies, that largely decide its value and supply. Main products, for example, are valued for properties that make them ideal as fuels for heating or transportation. As liquids they can be easily stored and delivered. They are sufficiently volatile to provide reasonably efficient combustion, yet are not so volatile as to be explosive and dangerous to handle. The fact that they are burned up as fuels implies that there will be a continuous, renewed demand for them by the general public. Arguably aviation gasoline and jet fuel, despite their small market shares, should not be included in the "other products" category for they are simply variations of main transportation fuels. As for the remaining "other products", their physical particularities at once stimulate and limit the demand for them. Thus, although a product such as propane is highly desirable as a fuel by virtue of its high volatility, it is nevertheless undesirable as a fuel because its volatility makes it difficult and dangerous to handle. At the other extreme, a product such as asphalt may be prized for its longevity or durability but this however implies low maintenance and replacement rates, and hence again relatively low sales.

Figure 1.4.1
Percentage Change in Demand since 1980



Since 1980 sales of "other products" as a percentage share of total petroleum product sales have risen from 16% to an estimated 21% in 1988. The increasing market share of "other products" does not reflect a change in demand for "other products", but rather a decline in demand for the main products. Largely because of increased fuel efficiency in transportation and heating on the one hand, and the loss of sales to the natural gas and electric power industries as a result of fuel substitution on the other, main product sales are currently about 20% below 1980 levels. "Other product" sales, however, are at about the same level now as in 1980, their sales apparently not as sensitive to energy conservation measures and substitution.

Following is a brief survey of the individual products that together comprise the "Other Products" category, with a focus on their applications and historical demand trends.

Table 1.4
1988 Market Share of Other Products Sales as a Percentage of:

	Total Refined Products	"Other Products"
Still Gas	0.2	1.7
Propane	2.3	10.8
Butane	0.9	4.7
Jet Fuel	5.8	28.9
Aviation Gasoline	0.2	1.0
Petrochemical Feedstocks	4.7	20.9
Asphalt	3.7	16.1
Petroleum Coke	1.6	7.3
Lubricating Oils and Greases	1.3	5.4
Naphtha Specialties	0.4	1.6
Miscellaneous and partially processed	0.5	1.7
Total	**21.5 %**	**100 %**

1.4.1 Petroleum Gases

During the course of refining crude petroleum, various hydrocarbon gases are produced. These include methane, ethane, propane and butane. Refinery still gas is largely made up of methane and ethane, which are also the principal elements of natural gas. Their extremely high vapour pressure and volatility generally render their storage at refineries problematic and uneconomic. Consequently, they are normally consumed as refinery fuel, thereby reducing the refinery's expenditures on natural gas and its own consumption of heavy fuel oil and coke.

About 95% of the 8 to 11 000 m^3/d of still gas produced in Canada (which amounts to about 5% of total refinery production) is consumed as refinery fuel. Only in Ontario does one find any sales of still gas, and these all emanate from one refinery that supplies a natural gas utility during the latter's peak load periods. Moreover, the high costs of storage and distribution, in conjunction with its comparatively low value, have precluded international trade in still gas.

Propane and butane, also known as liquified petroleum gases, or LPG's, are also gaseous at normal temperatures and pressures. Having higher molecular weights than either methane or ethane they produce lower vapour pressures, which render them more amenable to liquefaction through compression and/or cooling. As liquids, their volumes are reduced by about 250 times, implying a rich reserve of energy*.

In certain respects LPG's are ideal fuels because they may be stored as liquids but used as gases in combustion. Burned as gas LPGs are high-octane, and, comparatively-speaking, environmentally benign fuels. Ironically, the high vapour pressure and volatility that permit such clean and complete combustion and hence make these gases so attractive as fuels, are the same properties that have acted to limit LPG marketability, since storage and distribution are potentially hazardous, relatively costly and awkward.

Nevertheless, there are many applications, fuel-related and otherwise, to which propane and butane have been put. In Canada about 40% of propane production is used as a fuel for heating and cooking in the residential and commercial sectors and for process heating in the industrial sector. In recent years there has also been an attempt by both government and industry to develop a market for propane as an automotive fuel. The drive has met with only limited success, however. Although propane is a cheaper fuel than motor gasoline and diesel, particularly in light of the favorable tax treatment it receives, consumer perceptions, the lack of an extensive network of filling stations and the cost of engine modification all have militated against its widespread use. This has meant that the adoption of propane-fuelled motor vehicles has been most prevalent in transportation-intensive businesses (e.g. taxi companies and urban transit systems). Nevertheless from virtually nil consumption in 1980, the transportation sector now consumes about 15% of total propane production.

**It is important to remember in the following discussion that the refineries are only one source of LPG supply and a relatively small one at that. Natural gas processing plants in fact produce about 80% of all propane and butane in Canada.*

Figure 1.4.1.1
Supply/Demand For Refinery - Produced Propane
1980-1988 Average
000 m^3/d

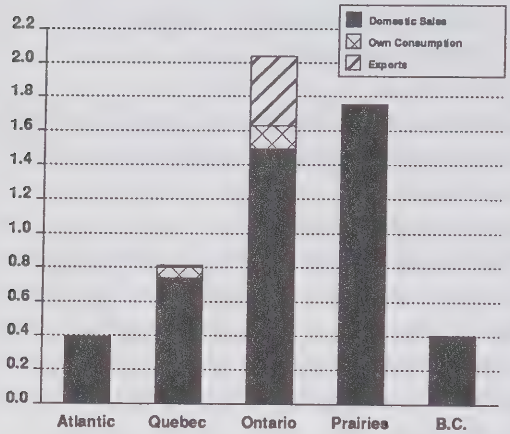
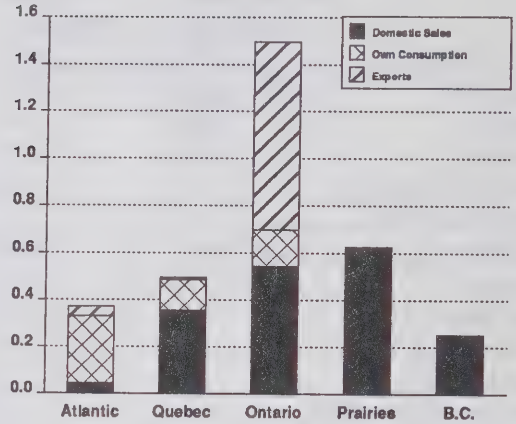


Figure 1.4.1.2
Supply/Demand For Refinery-Produced Butane
1980-1988 Average
000 m^3/d



On average about 4 to 5 000 m^3/d of propane have been supplied (ie net of interproduct transfers, own consumption etc) through Canadian refineries during the 1980s. However, supplies have risen steadily over the decade and are expected to surpass 5 000 m^3/d in 1988. This represents a 50% increase from 1981, the low point in the decade. With regard to domestic sales the market share of propane has increased from 1.3% to 2.2% of total product sales over this period and currently represents about 10% of the total sales of "other products".

Growth in butane production in the 80's has not been as dramatic with production generally being less than 3 000 m^3/d, from 1980 to 1988. Domestic sales of butane have normally represented less than 1% of total product consumption and less than 5% of "other product" sales. Butane demand, however, is expected to rise as a feedstock for methyl tertiary butyl ether (MTBE) which can be used as a substitute gasoline octane enhancer in lieu of lead-based products.

Exports of butane, as a percentage of refinery production and throughput, have normally been in the 25% to 35% range, while those of propane have ranged from 5% to 15%. LPG imports, on the other hand, have been virtually nil in the 1980's.

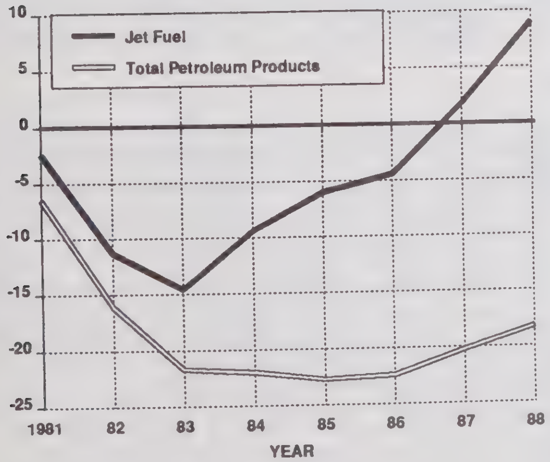
It is important to distinguish between the refineries' largely truck exports of LPG's and the pipeline and rail exports of LPG's produced at the natural gas processing plants. Exports of the latter swamp refinery exports by a ratio of 10 to 1. While these exports are more evenly distributed across Canada, virtually all the production occurs in Alberta.

On a regional basis, Ontario accounts for about a third of refinery produced LPG consumption, the Prairies another 30%, Quebec 20%, British Columbia 10%, and the Atlantic 5%. Ontario refiners export more than half their combined net butane production and throughput; whereas Atlantic refineries consume by far the greater part of theirs as refinery fuel, possibly because, on the one hand, they do not have a sufficiently large local or export market to sell to, and on the other, because they lack ready access to a supply of cheap natural gas as a refinery fuel.

1.4.2 Jet Turbo Fuel

Jet fuel is one of the most important "other products", both in terms of volume produced and sold, and contribution to refinery revenues. The application of the jet turbine engine for military aircraft propulsion during the Second World War, and its subsequent development for use in civil aviation, required a fuel that performed reliably under the wide variety of conditions experienced in aviation service. On the one hand, the fuel had to be a sufficiently volatile distillate to ensure instant engine start on the ground or during flight. On the other hand, given the combustion mechanics of the jet engine, the fuel had to provide flame stability during flight manoeuvres. Moreover, it was important that its viscosity be maintained at the low temperatures encountered in high-altitude flight. Jet-A, a kerosene-based fuel meeting these stringent requirements, was developed and is currently used by most of the civil airlines in the world. Between 75% and 85% of total jet fuel production in Canada is of this type. Nevertheless, the maximum yield on crude of a purely kerosene-based jet fuel is quite low - from 5 to 20% on crude depending on crude characteristics. To ensure supply in times of war, Jet-B, a naphtha-kerosene based fuel with a significantly larger yield on crude was developed for military aircraft, and subsequently modified for civilian airline use.

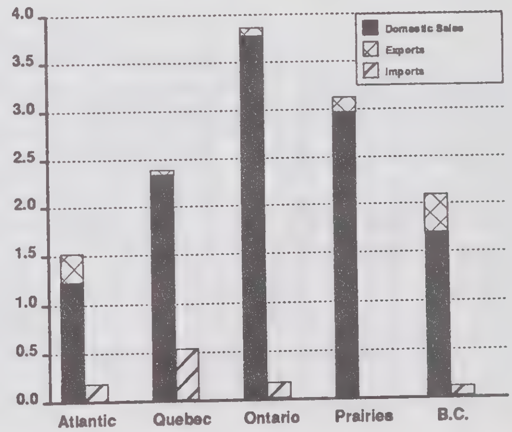
Figure 1.4.2.1
Jet Fuel Sales
Percentage Change Since 1980



In 1983 production of jet fuel in Canada was 11 000 m^3/d, its lowest point in the decade. Since then it has risen steadily, in conjunction with strong economic growth, with production in 1988 expected to surpass 13 000 m^3/d. Over the decade domestic sales have approximated domestic production, representing 5 to 6% by volume of total petroleum product sales, and about 28% of the total of "other products" sales. Sales reflect quite closely the seasonality of commercial airline travel in Canada (highest in the third quarter, lowest in the first), and the regional distribution of air traffic activity.

With regard to international trade, neither imports nor exports of jet fuel have been very significant although this may be changing. In the first half of the decade exports averaged less than 3% of production while imports averaged about 4%. Since 1985 however, both have risen rather sharply, possibly reflecting trade liberalization in the oil industry, to about 15% of production.

Figure 1.4.2.2
Supply/Demand for Jet Fuel
1980-1988 Average
000 m^3/d



The extent of trade in jet fuel appears to be largely determined by refinery access to marine tanker transportation. Thus export activity was heavily concentrated in the Atlantic and Quebec regions in the early years of the decade. Since 1983 when three refineries in Quebec were shut down almost all exports have come from either Atlantic or B.C. refineries. Imports have likewise been concentrated in these three regions, which together have accounted for between 80 and 100% of total jet fuel imports at any one time.

1.4.3 Aviation Gasoline

Aviation gasoline which is used to power aircraft piston engines accounts for a very small and shrinking share of refinery oil production and sales. In the 1980s, it has typically represented less than a quarter of a percent of total product sales, and about 1% of the total sales of "other products". As aviation turbine engines (turbo-jet and turbo-prop) have come to dominate in the propulsion of larger aircraft, use of the aviation piston engine has been relegated to a diminishing fleet of light airplanes and helicopters.

The octane rating in aviation gasoline is generally higher than motor gasoline permitting more power and higher fuel efficiency. Moreover, given that an aircraft may be exposed to a wide variety of climatic conditions, temperatures, and pressures during the course of a single flight, volatility and viscosity specifications must be standardized. This is in contrast to motor gasoline which may have varying specifications depending on season and geographic location. Finally, special care must be taken to ensure the removal of contaminants and water from aviation gasoline, as failure to do so could obviously spell disaster.

Between 1980 and 1982 domestic sales of aviation gasoline experienced a dramatic decline of 25%, from 650 m^3/d to 500 m^3/d, largely as a result of the economic downturn during that time. Since then sales have never recovered, and in 1988 were down a further 5%. This virtually uninterrupted decline reflects the dwindling use of piston-engine aircraft in Canada. The pronounced seasonality of sales, with two-thirds of annual sales in the spring and summer months follows from the fact that two of the major activities in which light aircraft are involved are recreation and crop dusting.

On a regional basis, a disproportionate share of aviation gasoline sales (about 38%) are in the Prairies and the Territories, reflecting the region's vast expanses, large grain farming sector, and numerous remote communities not easily accessible by means other than small aircraft. As for the other regions, the Atlantic provinces account for about 7% of sales, Quebec 13%, Ontario 24% and British Columbia 18%.

1.4.4 Petrochemical Feedstocks

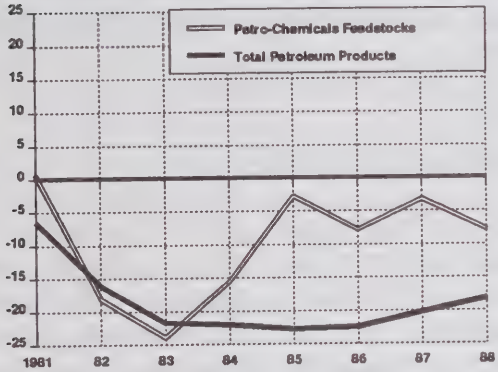
Oil-based petrochemical feedstocks are semi-refined products, whether these be LPGs, naphtha or middle distillates, that are used as raw materials for the production of petrochemicals. Petrochemicals themselves are used in the manufacture of such diverse synthetic materials as plastics, resins, rubbers, solvents, detergents and fibers. Despite their variety most petrochemicals are made from only a few base chemicals. Depending on the extent of vertical integration, these chemical building blocks may be produced by the refinery's own petrochemicals division or by independent petrochemicals manufacturers. For the most part these base chemicals are derivatives of ethane, propane and butane: that is, ethylene, propylene, butylene and butadiene. The natural gas industry is also an important source of LPG-based petrochemical feedstock supply (ie the olefins). The other major category, the aromatics, are mostly naphtha - derived and are produced in refineries and oil-based petrochemical plants. The main chemicals included in this group are benzene, toluene, and xylenes. Once petrochemicals are synthesized from these base chemicals they are then usually sold to the general manufacturing sector as inputs in the production of a myriad of end-user goods.

Demand for petrochemicals and, by association their feedstocks, should therefore correlate closely with the level of manufacturing activity in the economy. Moreover, as their quality and versatility improve and the prices of natural raw materials increase, petrochemicals are continuously being substituted for traditional materials in manufacturing. This implies growth in petrochemicals production over and above that found in the manufacturing sector, to the extent of this substitution.

In Canada production of petrochemical feedstocks by the refineries has been in a state of gradual decline since the turn of the decade. Annual production has fallen from almost 14 000 m^3/d in 1980 to less than 11 000 m^3/d in 1988. Total sales, on the other hand, after a experiencing a sharp decline of 25% during the recession years 1982-84, recovered almost fully to about 10 000 m^3/d in 1985 and have since remained relatively steady. To maintain domestic sales volumes in the face of falling refinery production, exports have declined while imports have increased. For instance, in the early 80's about 20%

of domestic production was exported while only 1% was imported. However, in the years 1987-1988 exports averaged about 15% while imports averaged 10% of production.

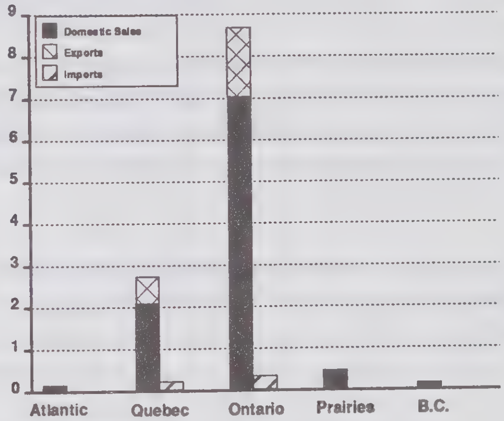
Figure 1.4.4.1
Sales of Refinery - Produced Petrochemical Feedstocks
Percentage Change Since 1980



It should not be inferred that the petrochemicals industry is in a state of stagnation or decline from the trends observed in production and sales of oil-based petrochemical feedstocks. In fact, the industry appears to be doing quite well. Since the data pertains to petrochemical feedstocks supplied by the refineries only, it does not include the increasingly large supplies of feedstock from the natural gas industry (primarily methane, ethane and LPG's.) Currently refineries supply only about a quarter of the petrochemical industries' feedstock requirements, and they have been steadily loosing ground to natural gas sourced supplies.

Refinery-produced petrochemical feedstocks have averaged between 4% and 5% of total annual petroleum product sales, and from 20 to 25% of "other product" sales, during the 1980's. Traditionally, almost three-quarters of feedstocks sales have been in Ontario (in 1986 it was as high as 85%), reflecting the large petrochemicals industry located there. Quebec, during the early years of the decade before the refinery closures, accounted for a third of national sales. Starting in 1983 however, its share declined rather sharply, falling to 6% by 1986 before recovering to a 15-20% range in 1987 and 1988. Sales in the Prairies have until recent years been quite small, this region's substantial petrochemicals industry being primarily natural gas based. Starting in 1985, however, the share has gradually increased such that about 10% of refinery petrochemical feedstock sales are now in the Prairies.

Figure 1.4.4.2
Supply/Demand For Refinery-Produced Petrochemical Feedstocks
1980-1988 Average
000 m^3/d



1.4.5 Asphalt

Asphalt, also known as bitumen or tar, is a non-volatile residue left over from the distillation of crude oil. At normal temperatures it is solid or semi-solid; however, on heating it softens and at higher temperatures becomes fluid. This ability to transform from a solid to a more malleable state and vice versa, in addition to some other desirable properties such as its durability, impermeability and adhesiveness (not to mention its comparatively low price) makes asphalt an excellent material for a wide variety of applications in the surfacing and construction materials industries.

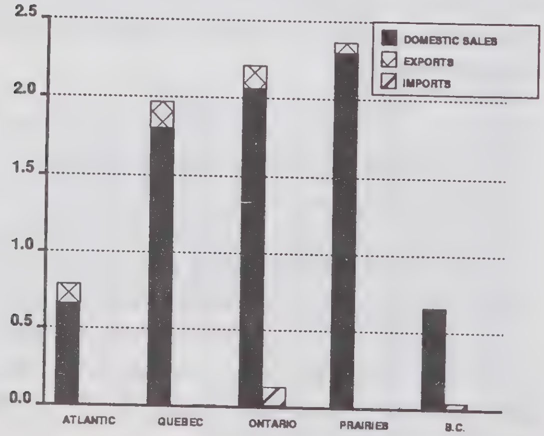
The biggest source of demand for asphalt comes from the road construction and maintenance industry. Asphalt mixes, generally consisting of asphalt, gravel, sand and clay have become the usual paving material for road surfaces. This is in recognition of the flexibility and lower costs of construction, relative to concrete roads, that asphalt roads afford. Depending on the grade of road from 5% to 10% by weight of the asphalt mix is actually asphalt, its primary function being to bind together the other components of the mix.

Asphalt is also commonly applied as a sealant to exterior walls of building foundations and waterworks so as to prevent water seepage and decay. It also makes an ideal adhesive when laying roofing, flooring and insulation. In the construction materials industry, asphalt is an important ingredient in the manufacture of such products as roofing shingles and tar paper.

On average over 8 000 m^3/d of asphalt is presently produced in Canada. This represents over 3% of total petroleum product output, and about 17% of "other products" output, in volumetric terms. Domestic sales normally approximate production. The importance of construction generally, and road construction and maintenance specifically, to asphalt sales is revealed in the highly skewed distribution of annual sales, whereby almost half of sales occur in the summer and only about 7% in the winter.

The extent of road construction in any given region is a function of both the size of the population and its distribution or dispersion. The Prairies (and Territories) with their widely dispersed communities account for a large fraction of total asphalt consumption. With only 18% of the Canadian population these regions account for over 30% of asphalt sales, producing a ratio of consumption to population of around 1.7 to 1. On the other hand, Ontario, with its population largely concentrated in the Golden Triangle area, has 36% of the population but only 27% of asphalt sales, producing a ratio of 0.75.

Figure 1.4.5
Supply/Demand For Asphalt
1980-1988 Average
000 m^3/d



Over the 80's exports of asphalt have dominated imports by a ratio of 3 to 1, with exports accounting for an average 6% of production and imports, 2%. High transportation costs imply that asphalt sales will tend to be to end-users in relatively close geographic proximity to the refinery, irrespective of whether they are located within the same political boundaries. This tendency likely explains in part why a surprisingly large share (generally over 50%) of asphalt exports come from refineries in Quebec and the Atlantic. They happen to be ideally situated to supply the northeastern New England states (ie Maine, Vermont, and New Hampshire) which lack refineries of their own.

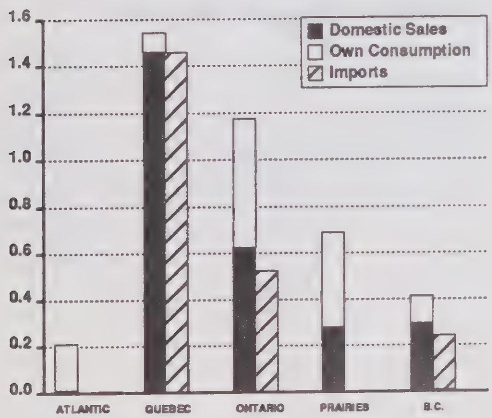
1.4.6 Petroleum Coke

Literally the "bottom of the barrel" of refined petroleum products, petroleum coke is a dry, porous, essentially pure carbon residue left over from the refining process. In Canada the aluminium industry is a major user of coke carbon. Raw aluminium ore (bauxite) is an aluminium-oxygen compound. To obtain pure aluminium the oxygen is separated from the aluminium by means of electrolysis in a chemical bath. Rods of high-grade coke are employed as electrolytic anodes whose positive electrical charge attracts and combines with the negatively-charged oxygen to form carbon monoxide and dioxide gases. A lot of coke is thereby vaporized in the process; in fact roughly two-thirds of a tonne of coke is consumed for every tonne of aluminium produced. Refining aluminium by electrolysis requires massive amounts of electric power, which is why aluminium refining is concentrated in Quebec and British Columbia. These two regions are also the principal consumers of high-grade coke in Canada.

The other major use of coke (generally of a lower grade with more impurities) is as a thermal fuel. Much of Canadian refinery production is of this low grade. Coke is sufficiently porous and dry to permit good high temperature combustion. Therefore, heat-intensive industries, often located in close proximity to a low-grade coke-producing refinery, will install coke-burning facilities in order to take advantage of this cheap supply of fuel. Cement manufacturers are notably heavy consumers of thermal coke. When supply exceeds demand, as is normally the case, the excess coke is consumed as a fuel in refining operations.

Production of petroleum coke in Canada (both low and high grade) has fluctuated between 1 300 m^3/d and 2 200 m^3/d during the 1980's, representing less than 1% of total petroleum product production. Imports of mainly high grade coke have, in many years, been as high or higher than total domestic production. In 1986, for example, when domestic production was at its lowest point in the decade, twice the amount of coke was imported as was produced domestically. On the other hand, there have been no exports, a reflection of the low grade and value of most Canadian coke, in conjunction with high associated transportation costs. This has meant that domestic sales have been usually greater than production, representing about 1 to 1 1/2% of petroleum product sales. Sales would have been substantially greater still were it not for the fact that, typically, three-quarters of domestic production is consumed as refinery fuel.

Figure 1.4.6
Supply/Demand for Petroleum Coke
1980-1988 Average
000 m^3/d



High-grade anode coke is imported by the boat-load in Quebec and British Columbia, reflecting the major aluminium refining industries in these regions. It is interested to note that although Quebec and British Columba are major consumers of coke most of their consumption is of high-grade coke imports. These two regions combined account for almost 80% of all coke imports. Some Prairie refineries also supply anode-quality coke to the aluminium industry in British Columbia. Ontario imports coke for metallurgical and thermal purposes and likely also for the manufacture of graphite products.

1.4.7 Lubricating Oils and Greases

Lubricating oils and greases are applied to the moving parts of machinery to reduce friction, wear and corrosion. Although they account for only about 1% of total refined product sales and production in Canada, they have a high unit value and hence contribute significantly more than their volumetric share to refinery revenues. In part at least, their relatively high prices stem from the fact that in order to improve the properties of the lubricants (ie their stability, viscosity, etc.) valuable chemical additives are often blended into the final product.

Considerable research has been invested in the science of lubrication in light of its implications for energy efficiency and machine life. This has led, as in the case of the petrochemicals industry, to the establishment of independent specialist firms that purchase base oils from the refineries and then proceed to tailor-make, by blending in their own additives, lubricants best suited for particular applications. The refineries however continue to dominate in the big lubricant markets such as automobile motor oil.

On average about 2 500 m^3/d of lubricating oils and greases are produced in Canada. Sales have averaged about 8% higher than production, reflecting the fact that, with the exception of 1982, Canada has been a net importer of lubricants. Since 1986 imports in fact have increased substantially, reaching as high as 30% of domestic production in 1987. Meanwhile exports have remained relatively steady, fluctuating between 2-4% of production.

The industrial sector (ie manufacturing and mining) is the biggest consumer of lubricants accounting for about 45% of sales. The transportation sector is another major user typically accounting for 30% of sales. About 45% of sales are in Ontario, as are three-quarters of Canada's imports and 90% of exports. The Prairie region accounts for about 22% of sales, Quebec 15%, the Atlantic region 7% and British Columbia 10%.

1.4.8 Naphtha Specialties

Naphtha specialties consist primarily of liquid solvents and cleaning agents. Important applications are found in the paint and dry cleaning industries. Varsol is a well

known example of a naphtha speciality. In Canada, production of naphtha specialties has fallen by over a half since the turn of the decade, from 2 000 m^3/d to 1 000 m^3/d. Domestic sales are also down by 50% to 750 m^3/d, leaving this product with a current market share of only about a third of one percent of total refined product sales.

Exports represent a sizeable proportion of domestic production, in many years, amounting to over 40%. By comparison, imports have been insignificant, averaging roughly 3% of production.

About two-thirds of naphtha specialties sales are in Ontario. Ontario also currently accounts for about 80% of exports. British Columbia has been increasing its exports, particularly in the last three years such that in 1988 it will account for about 20% of exports. Nevertheless, B.C. domestic sales comprise only 6% of Canadian demand. As for the other regions only Quebec has had sales above 10% of total domestic sales.

1.4.9 Miscellaneous and Partially Processed Products

This category is a "potpourri" of finished and unfinished products which, when aggregated, average only about a third of one percent of total petroleum product volumes. The finished products, which are available for sale, are primarily petroleum waxes and jellies. The waxes, which may also be in paste, cream or liquid form, are used in various applications: in candle making; the manufacture of polishes for leather goods, furniture, floors and cars; and, in the making of wax paper and cardboard. Petroleum jellies, on the other hand, are important ingredients in the manufacture of certain cosmetics and skin-care ointments.

Domestic sales have averaged about 1 000 m^3/d in the 1980's; however this conceals large swings. Consumption of the miscellaneous products therefore has never amounted to much more than one half of one percent of total product sales and has often been considerably less. About 45% of these sales have been in Ontario, 28% in the Prairies, 15% in Quebec, 12% in B.C. and only 1% in the Atlantic region over the decade.

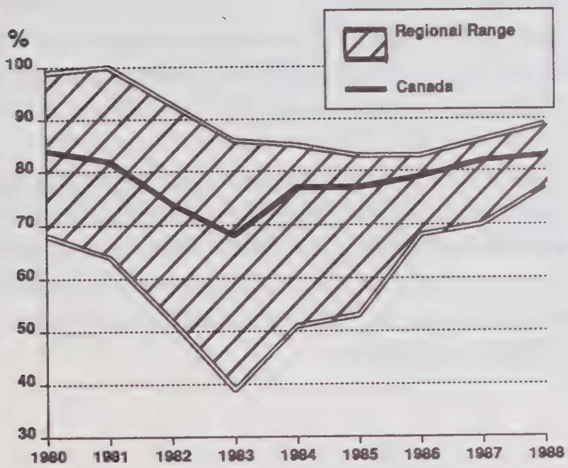
2. Refinery Utilization

- *Refinery utilization reached a seven-year high in 1988, at about 83%, reflecting higher consumption and increased product exports.*

- *Utilization rates are forecast to increase again in 1989*

Crude oil run to stills was higher throughout 1988, and averaged 250 000 m^3/d, up 6% from 1987. The national refinery utilization rate rose almost 2 points in 1988, to reach a seven-year-high level of 83%. This represented a 15 percentage point improvement from the 1983 low of 68%.

Figure 2.1
Refinery Utilization
1980-1988

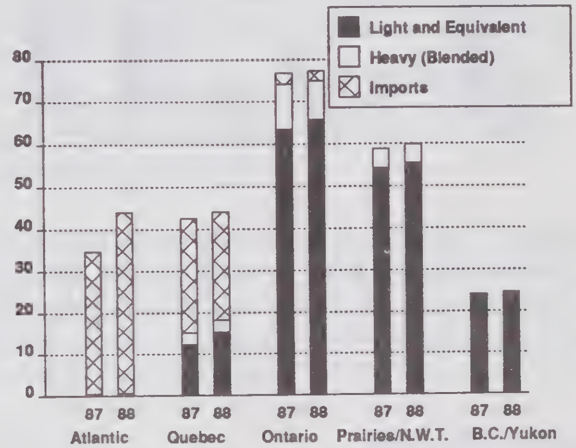


Approximately one half of the increase over the last five years is attributable to refinery closures and modifications, particularly in eastern Canada. The other half of the growth reflected increased demand in 1987 and 1988, in both the national and international markets, as product exports also rose, particularly in the Atlantic region. As illustrated in figure 2.1, with the increase in throughput in the Atlantic region (which represents the lower boundary of the shaded area of the graph), the range of utilization rates among the regions has narrowed since the first half of the decade.

Total feedstock receipts (including partially processed oil) in 1988 averaged 250 000 m^3/d, up more than 5% from 1987. The increase was divided about equally between imports and domestic crude, with much of the increase in imports attributable to the reactivation of the Come-by-Chance refinery. Light and synthetic crude accounted for all the increase on the domestic side.

Figure 2.2
Crude Oil and Equivalent Receipts by Region
(Annual)

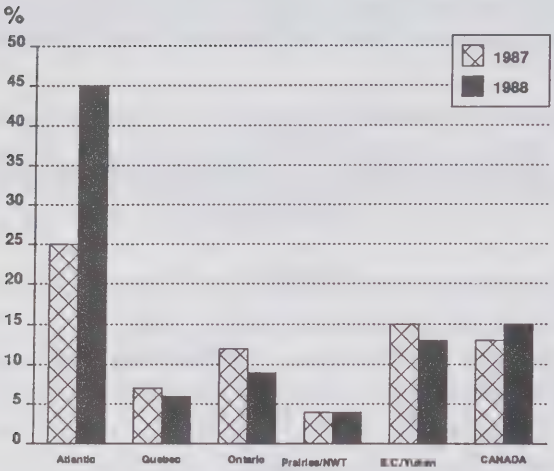
000 m^3/d



On a regional basis, the greatest increase in receipts was in the Atlantic, where imports rose 30%. Although oil product consumption was up 5%, most of the increase reflected crude oil processing for the export market. In 1988, this became even more important in the Atlantic, accounting for about 45% of refinery throughput, compared with 25% in 1987. As a result of the increased export throughput, refinery utilization increased 7 points to 77%; however, it still remained the lowest of all the regions.

Utilization rates were up slightly in the other regions, ranging from 83% in Ontario to about 91% in British Columbia. The increased throughput was met entirely by domestic crude. A substantial portion of the increase was in Quebec where deliveries of domestic crude oil increased more than 29%, reflecting a reduction in western Canadian pipeline bottlenecks and a continued price advantage over imported crude, which led to lower import levels.

Figure 2.3
Exports As A Percent of Total Refinery Throughput



In British Columbia more partially processed crude was run, rather than crude oil, to meet incremental requirements. Throughput for the export market was down slightly from 1987.

Outlook for 1989

According to refiners' submissions to the NEB (January 1989), programmed demand by domestic refiners for crude oil and equivalent in 1989 will be about 5% higher, at 263 000 m^3/d. Domestic product consumption is programmed to rise 3%. With respect to product trade, the relative improvement afforded Canadian refiners by the Free Trade Agreement should result in higher product exports, but the magnitude is difficult to estimate. Assuming there are no changes to refinery capacity, the utilization rate would also increase, by about 3 percentage points, to 86%.

With respect to the mix of crude oil deliveries, programmed demand for heavy crude is expected to reach 25 000 m^3/d - a 45% increase - primarily reflecting the start up of the Newgrade upgrader, which in turn, will provide synthetic crude to the Consumer Co-op refinery in Regina, Saskatchewan. Despite the displacement of up to 7 000 m^3/d of light crude feedstock with heavy, total light crude demand is programmed to be down only slightly, with much of the decline in Prairie requirements offset by gains in Ontario and Quebec.

In British Columbia requirements for crude oil are programmed to drop 10%, to 19 000 m^3/d; however, use of partially processed oil and other feedstocks is expected to almost double, to 6 500 m^3/d.

On the import side, forecast drops in Ontario and Quebec will offset about two thirds of the Atlantic increase for a net increase in total imports of 2 000 m^3/d, or 3%.

In Quebec the domestic/import split is programmed to narrow to 47/53 from 38/62 in 1988, because of an increase of more than 3 000 m^3/d in domestic deliveries which will tend to improve the economics of shipping crude oil through the Interprovincial Pipe Line (IPL) Sarnia-Montreal extension.

3. Pipeline Utilization

- *Major crude oil pipelines out of western Canada operated near capacity in 1988*
- *Some minor line space allocation required on the IPL system.*
- *Pipeline deliveries to Montreal increased.*

3.1 Trans Mountain Pipe Line Deliveries

Trans Mountain Pipe Line (TMPL) throughput for the fourth quarter of 1988 averaged 27 500 m^3/d, up 10% from 1987. While crude oil and product deliveries for domestic use accounted for just over 80% of these deliveries, most of the incremental volume was related to an increase in crude oil exports, in particular heavy crudes.

Exports of crude oil, split almost equally between light and heavy, reached 4 400 m^3/d, about 75% higher than a year ago. A decline in light crude exports, as a result of IPL expansion and higher U.S. midwest netbacks, was offset by a dramatic increase in heavy crude exports. Heavy crude exports, spurred by producers' search for market alternatives to the U.S. northern tier, increased to 2 400 m^3/d, 73% higher than in the fourth quarter of 1987.

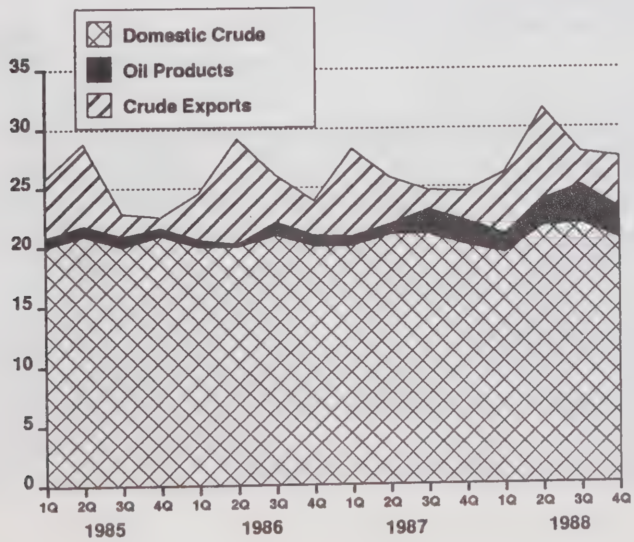
Crude oil deliveries to B.C. refiners (including nearly 5 000 m^3/d of partially processed oils) at 20 500 m^3/d, were unchanged from last year. Petroleum product deliveries reached 2 600 m^3/d, 20% higher. West coast demand is increasingly being met by more partially refined and finished product movements from Edmonton.

The trend in deliveries on an annual basis was similar to the fourth quarter. In 1988, pipeline throughput increased 8% to 28 200 m^3/d, with all of the increase made up of exports by tanker, which were 50% higher, at 3 400 m^3/d, and product movements, which rose 60% to 2 300 m^3/d. Deliveries to B.C. refiners were up slightly; however, crude oil deliveries declined and were replaced by partially processed oils, up 35% to 3 000 m^3/d.

Pipeline utilization for 1988 was 85%, five percentage points higher than in 1987.

In the spring of 1988, the National Energy Board (NEB) conducted hearings on a proposed two-stage expansion of TMPL facilities to move heavy crude oil and methyl tertiary butyl ether (MTBE), an octane enhancer for gasoline, to the export market via Vancouver.

Figure 3.1
Trans Mountain Pipe Line Deliveries
000 m^3/d



The first-stage expansion was approved in August. A subsequent appeal to the Board and the Federal Court of Appeal by environmental and residential interests in the Burnaby, B.C. area was rejected. The second-stage of the extension was denied because the original TMPL request did not address the need for additional terminal facilities.

A third-stage expansion which would double the system capacity, remains under review. Section 4.4 provides a review of the most recent long-term oil forecasts prepared by the NEB and the Alberta Energy Resources Conservation Board (ERCB) and the potential impact on the need for, and timing of, proposed pipeline expansions.

3.2 Interprovincial Pipe Line

Total Interprovincial Pipe Line (IPL) deliveries of crude oil and other hydrocarbons, including petroleum products and natural gas liquids during the fourth quarter of 1988, averaged 240 000 m^3/d, 3% higher than a year earlier. Petroleum products and NGLs accounted for about 10% of deliveries, with crude oil making up the balance.

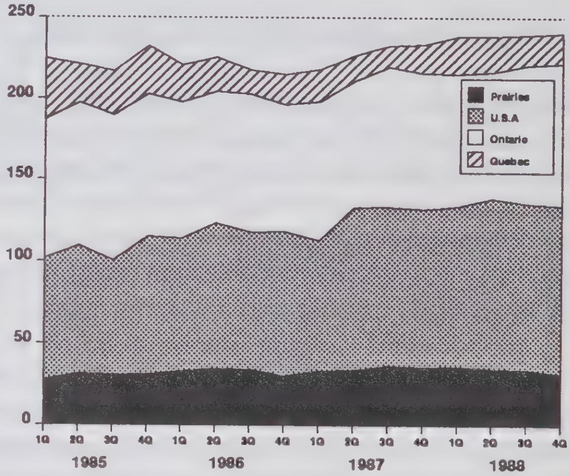
Fourth-quarter deliveries included 137 700 m^3/d destined for domestic markets, with most of the remainder for export to the United States. Deliveries to U.S. markets increased by 7% over last year. Ontario and Quebec were the only domestic markets to register an increase in deliveries. Deliveries to Ontario increased by 5% to 87 000 m^3/d while Quebec increased by 2% to 19 000 m^3/d. Western refiners (east of the Rockies) received 32 000 m^3/d, 12% less than last year.

As a percentage of total IPL deliveries, heavy crude represented about 30% of the mix, unchanged from last year. Light crudes declined slightly, to about 51%. Deliveries of synthetic crudes doubled to nearly 5% of deliveries, with the increase split almost evenly between U.S. and Ontario markets.

On an annual basis, IPL deliveries increased to 239 000 m^3/d, 5% higher than 1987, because of increased capacity and strong refiner demand. All domestic markets maintained their levels of deliveries while the Quebec take increased by 20% to 21 000 m^3/d (including shipments east of Montreal). Deliveries to U.S. markets showed the largest volumetric growth, increasing 9 000 m^3/d, or 9%, to 101 000 m^3/d. The crude oil mix varied little from the fourth quarter.

Figure 3.2
Total IPL Deliveries

000 m^3/d



Despite capacity additions prior to 1988, and a small expansion in the fall of 1988, IPL still had to apportion pipeline space, by an average of about 18 000 m^3/d in 1988. Over-nominations by shippers was the major factor, although IPL also continued to be marginally short of capacity. (For further details see Section 4.)

In October 1988, IPL applied for a $29 million increase in its cost of service, which equated to a 5% tariff increase for 1989. About half of the increase was related to a forecast increase in power costs charged by the Saskatchewan Power Corporation (SaskPower). Because of discussions between oil producers and SaskPower, a 5% general rate increase, previously scheduled, was not imposed on IPL in 1989. As a result of the reduction in the anticipated power cost increase, the 1989 tariff increase granted by the NEB was reduced to about 4%. The savings to oil producers in 1989 is expected to be about $4.5 million. Effective January 1, 1989, the basic light crude toll on the Canadian portion of the line, from Edmonton to Sarnia increased $0.14/$m^3$, to $3.47/$m^3$.

3.3 Montreal Pipeline Utilization

During the fourth quarter of 1988 Montreal crude oil deliveries via IPL's Sarnia-Montreal pipeline and the Portland Pipe Line averaged 27 500 m^3/d, a decrease of 2 500 m^3/d or 8% from the same quarter a year earlier. Total domestic deliveries at 18 700 m^3/d were marginally higher than a year ago; however, imported crude via the Portland-Montreal pipeline declined by nearly 25%, to 8 800 m^3/d. Of the domestic receipts, about 1 000 m^3/d were for transshipment as exports or domestic transfers compared with 2 000 m^3/d during the fourth of quarter 1987.

On an annual basis, receipts at Montreal terminals totalled 32 000 m^3/d, up 8% from 1987. The Sarnia-Montreal portion of the IPL moved an additional 3 200 m^3/d of domestic crude, for a total of 21 000 m^3/d. The Portland-Montreal system delivered 10 800 m^3/d, about 2 000 m^3/d less than the year before. The decline in Portland-Montreal deliveries reflected greater capacity on the western section of the IPL system (since the third quarter of 1987) and, as a consequence, increased availability of competitively-priced domestic crudes.

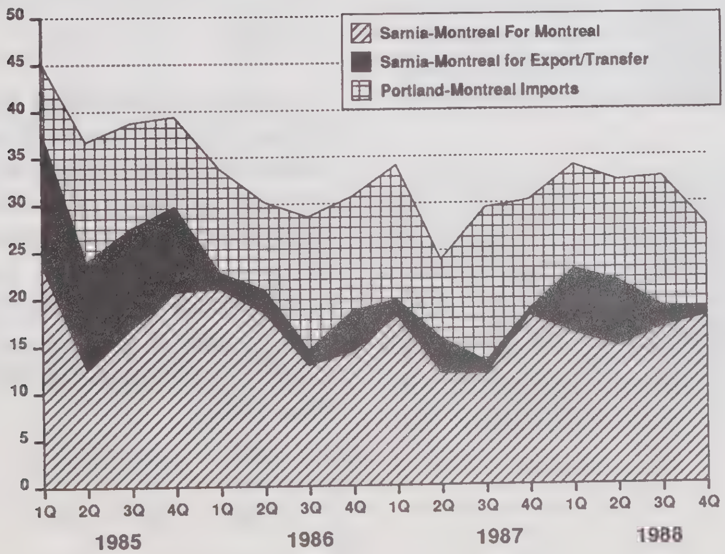
Additional Sarnia-Montreal pipeline deliveries to the Montreal area also reflected higher petroleum product demand (in particular for heavy fuel oil), increased domestic crude transfers to the Atlantic region refiners and higher crude exports out of Montreal to the United States (PAD District I) and Europe. Heavy crude deliveries increased by 40%, to 6 200 m^3/d, with over half of these deliveries exported compared with one quarter last year. Light crude oil deliveries increased by 18%, to 13 500 m^3/d. Partially processed oil deliveries declined slightly to just over 1 000 m^3/d.

The Sarnia-Montreal pipeline utilization rate for 1988 averaged 41%, seven percentage points higher than last year. Over the same period, the Portland-Montreal system utilization rate fell six percentage points, to 36%.

For more pipeline information see Appendix I which illustrates the location and current throughput capabilities of all major crude oil pipelines in Canada.

Figure 3.3
Crude Oil Deliveries to Montreal

000 m^3/d



4. Crude Oil Supply and Disposition

- *In 1988, conventional light crude oil productive capacity fell marginally while heavy crude oil rose 9%.*
- *In the second half of the year several bitumen projects were put on hold, pending higher prices.*
- *Light crude demand in both domestic and export markets increased.*
- *Sales of heavy crude oil to the export market rose by 15% whereas domestic demand remained unchanged.*
- *Long term oil supply outlooks by both the ERCB and the NEB are significantly more optimistic than previous forecasts for conventional crude oil, while mining plants and bitumen projects appear to be more price sensitive*

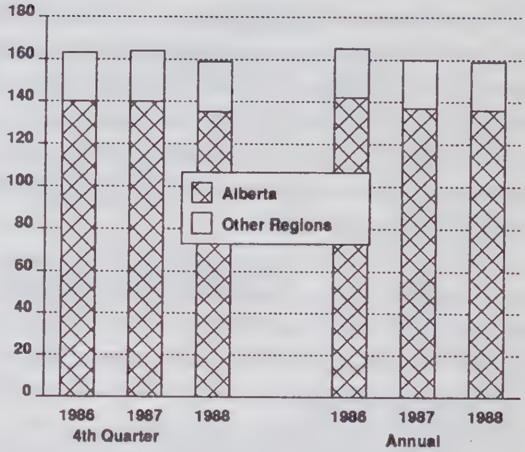
4.1 Light Crude Oil Supply and Disposition

During the second half of 1987 there was an increase in estimated Alberta conventional light crude oil productive capacity for the last half of 1987 and the year 1988, because the completion of the three phased IPL expansions in June 1987 allowed producers to test field capacity limits. As a result, conventional light crude capacity in Alberta only declined by 1 000 m^3/d, or less than 1%, in 1988, compared with a 3% drop in each of the previous two years. Most of the decline occurred during the fourth quarter, when productive capacity dropped by 5 000 m^3/d to 135 000 m^3/d.

This unexpected additional supply capability put pressure on the IPL system, particularly in the first half of the year, and resulted in 2 000 m^3/d of shut-in light crude oil. As a result of the IPL expansions, however, shut-in was much less than in 1986 (16 000 m^3/d) and 1987 (7 000 m^3/d).

Figure 4.1
Conventional Light and Medium Crude Oil Productive Capacity

000 m^3/d



Despite a drop of 8% in British Columbia, productive capacity outside Alberta in 1988 increased by 1% to 23 000 m^3/d. Norman Wells output accounted for most of the increase, reflecting greater on-site storage capacity.

In response to the oil price decline of early 1986, the oil industry has significantly reduced operating and exploration costs, sought technical innovations and pushed for lighter royalty and taxation burdens. As a result, despite the price decline, the oil industries in most non-OPEC countries, including Canada, have managed to maintain short-term conventional oil production, or at least, kept declines well below levels forecast by industry observers in 1986.

In addition, the Canadian long-term oil supply outlook appears brighter than previously forecast. As outlined in section 4.4, both the National Energy Board and the Alberta Energy Resources Conservation Board recently published long-term Canadian supply forecasts. Both forecasts are significantly more optimistic for conventional, as well as for total crude oil supply. This more positive view in part reflects the above-mentioned efficiency and fiscal regime changes which have occurred since 1986.

With respect to synthetic crude oil, production rose by 11% to almost 32 000 m^3/d in 1988, primarily because of a return to full production at Suncor following the 1987 fire, and the completion of the Capacity Addition Program (CAP) at Syncrude in the fall of 1988, which increased plant capacity from 25 000 m^3/d to 28 000 m^3/d. Despite a breakdown at the Syncrude plant in December due to mechanical problems Syncrude output in both the fourth quarter and for the year were at record levels of 26 000 m^3/d and 24 000 m^3/d respectively. In addition, it was the fourth year in a row that Syncrude recorded an increase.

Pentanes plus supply reached almost 19 000 m^3/d, up marginally from last year, reflecting higher natural gas production to satisfy export and domestic demand.

Table 4.1
Light Crude Oil and Equivalent Production and Disposition

	1986	1987	1988
		(000 m^3/d)	
Production			
Alberta	126.1	130.0	134.0
Other regions	22.6	22.7	23.0
Synthetic	29.2	28.5	31.6
Pentanes Plus	16.4	18.5	18.7
Total	**194.3**	**199.7**	**207.3**
Inv.(Draw)/Build	**(0.2)**	**1.1**	**(2.2)**
Net Supply	**194.5**	**198.6**	**209.5**
Demand			
Quebec	13.2	10.5	13.2
Ontario	62.4	61.0	63.3
Prairies	48.1	51.0	52.1
B.C.	20.8	21.0	20.6
Domestic Demand	**144.6**	**143.5**	**149.2**
Exports	**41.3**	**44.2**	**49.0**
Diluent for heavy (excl. recycled)	**8.6**	**10.9**	**11.3**
Total Demand	**194.5**	**198.6**	**209.5**

Total light and equivalent crude oil production averaged 207 000 m^3/d, up 4% from a year ago and accounted for over three quarters of total Canadian crude oil production. This increase mainly reflects the previously-mentioned increase in pipeline capacity, lower operating cost and technological improvements. Despite lower crude oil prices in 1988, total light and equivalent crude oil production reached the highest level since 1980.

Approximately 70% of net light crude oil supply was delivered to Canadian refiners, down slightly from 1987. With the exception of B.C., where deliveries fell marginally to 21 000 m^3/d because of greater use of partially processed oil, demand from all other regions increased. Quebec deliveries recorded the largest increase, up 26% (3 000 m^3/d). This increase reflected substitution away from imports to domestic supplies, in addition to higher refinery throughputs. On a Canada wide basis, most of the additional deliveries were synthetic crude. Exports were up by 5 000 m^3/d to 49 000 m^3/d.

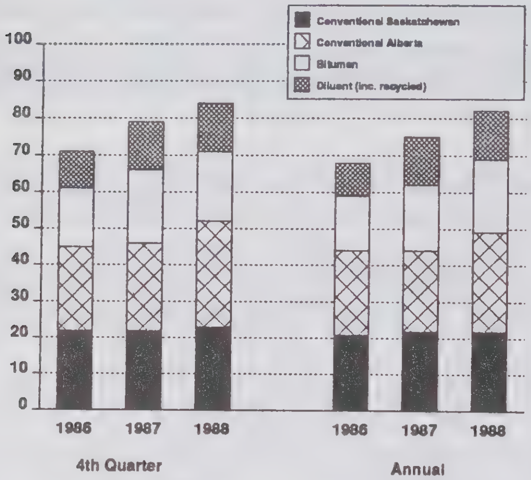
4.2 Heavy Crude Oil Supply and Disposition

Despite a decline of around $6.50/bbl in heavy crude oil prices in 1988, overall "neat" heavy crude oil productive capacity in 1988 increased by 9% to almost 68 000 m^3/d. While this volume represents the highest-ever productive capacity level of heavy crude oil, if current low prices persist, further increases in heavy crude supply are unlikely in the near term. During the fourth quarter the increase in capacity was only 3%, as low oil prices began to have an impact, particularly with respect to bitumen projects.

Conventional crude oil supply rose by 4 000 m^3/d to 48 000 m^3/d, and represented 70% of heavy crude oil production. Most of the increment occurred in Alberta, up 17% to 25 000 m^3/d, while Saskatchewan supply rose marginally, to 23 000 m^3/d. Much of the additional Alberta supply was added in the Bow River area, in part, because of quality/price competitive advantages against other crudes and ready markets.

Figure 4.2.1
Heavy Crude Oil Productive Capacity

000 m^3/d



In contrast to 1985 and 1986, when raw bitumen supply registered increases of 90% and 75%, the growth rate started to decline in 1987 with an increase of 25%. The slowdown became more apparent in 1988, with supply increasing only 10%, to 20 000 m^3/d. In addition, as of the third quarter of 1988 a flattening of the upward trend has been observed, mainly as a result of lower world oil prices which had the effect of slowing down and deferring the development of some projects, such as Shell Canada at Peace River and Esso Resources at Cold Lake. Moreover, several producers during the second half of 1988 began to delay required maintenance of some marginal wells consequently increasing the shut-in volume. As a result, the first year-over-year decline in bitumen capacity was recorded in the fourth quarter (down 1 000 m^3/d to 19 000 m^3/d).

Pentanes plus requirements (including recycled) for blending purposes averaged 12 300 m^3/d, up 5% from last year. The blend ratio remained constant however, at 1 cubic metre of pentanes plus to be used as diluent for each 5 cubic metres of raw heavy crude oil. This unchanged blending ratio reflects higher production of conventional heavy crude oil requiring marginal amounts of diluent (Bow River crude, at 26° API, can be transported without diluent) which offset the growth in bitumen, with higher diluent requirements.

Total blended heavy crude capacity was up 10%, to 83 000 m^3/d, representing 29% of total available supply of Canadian crude oil and equivalent.

Table 4.2
Heavy Crude Oil Production and Disposition

	1986	**1987**	**1988**
		(000 m^3/d)	
Production			
Conventional	39.9	42.9	45.6
Bitumen	14.8	18.4	20.3
Diluent (inc. recycled)	9.4	11.7	12.3
Total	**64.1**	**73.0**	**78.2**
Inv.(Draw)/Build	**(3.7)**	**(0.7)**	**(3.6)**
Net Supply	**67.8**	**73.7**	**81.8**
Demand			
Atlantic	0.3	0.4	0.6
Quebec	2.4	2.8	2.7
Ontario	8.3	10.5	9.3
Prairies	4.5	4.5	5.1
B.C.	0.0	0.2	0.3
Domestic Demand	**15.5**	**18.4**	**18.0**
Exports	**52.3**	**55.3**	**63.8**
Total Demand	**67.8**	**73.7**	**81.8**
Recycled Diluent	**0.9**	**0.8**	**1.0**

Total heavy crude oil production in 1988 averaged 78 000 m^3/d, up 6% from 1987. Shut-in rose from 1 500 m^3/d to 3 000 m^3/d, mainly because of falling crude oil prices.

Despite a substantial decline in domestic demand by Canadian refiners during the third quarter, total demand in 1988 only fell marginally, to 18 000 m^3/d. The largest decline was in Ontario reflecting some substitution back to synthetic and conventional light crude and reduced asphalt demand. Heavy crude oil exports were about 64 000 m^3/d (97% to the United States) and accounted for 81% of total heavy crude oil production.

It should be noted that when the Newgrade upgrader became fully operational in the fourth quarter, (it began operations in December) there was a decline in exports, as up to 8 000 m^3/d of mainly Lloydminster and Fosterton crude were diverted from the export market to the upgrader.

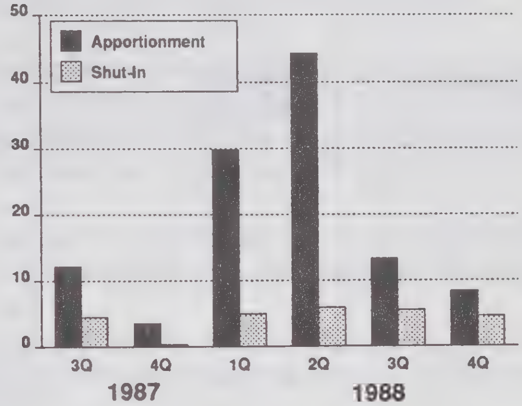
IPL Apportionment

IPL apportionment during the fourth quarter of 1988 averaged 4% or about 9 000 m^3/d. Crude oil supply exceeded pipeline capacity in November and December but no apportionment was necessary in October. Pipeline maintenance also contributed to the apportionment.

Most of the IPL apportionment in 1988 occurred during the first half, when overnominations were the centre of the problem. As a result, a committee made up of both industry and the provincial government was created early in the year to explore ways to reduce the problem. The implementation of a new verification process for notices of shipment was a success, as IPL apportionment during the second half was only about 10 000 m^3/d in comparison with 27 000 m^3/d during the first half.

While the IPL system was full throughout 1988, both Trans Mountain and the Rangeland systems had excess capacity through much of the year, indicating that factors (primarily low prices) other than potential transport constraints were also contributing to shut-in productive capacity.

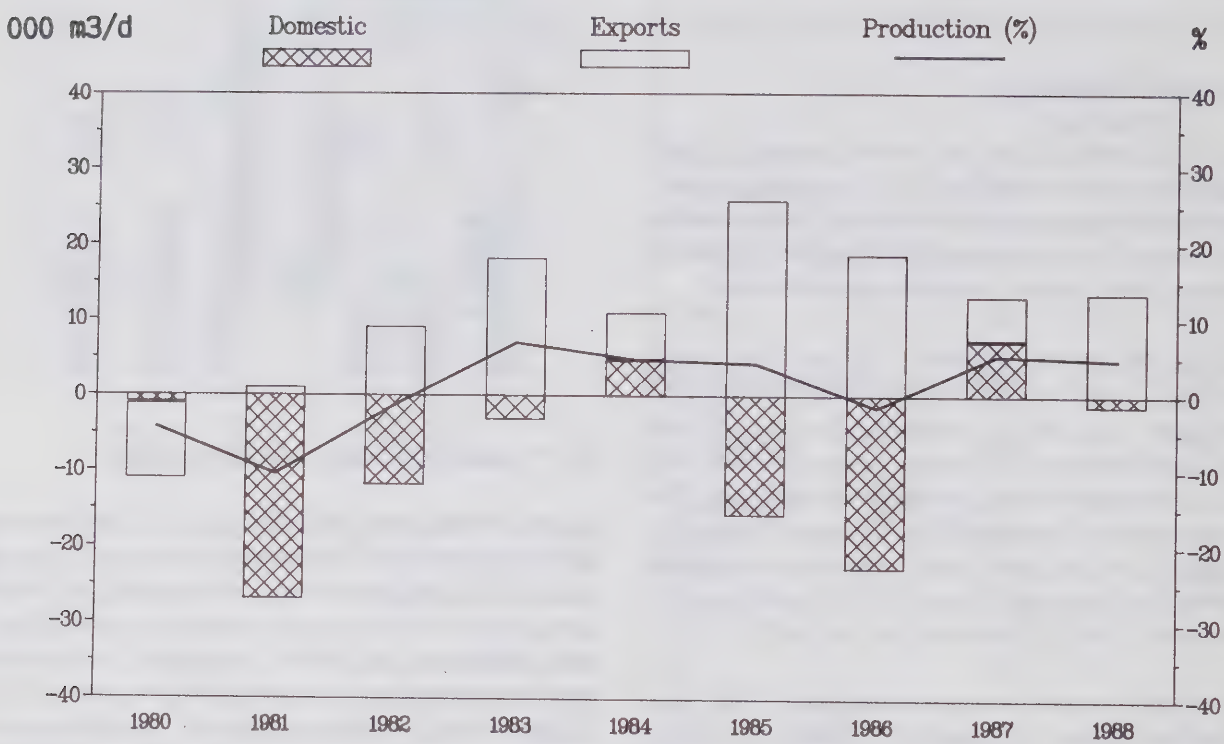
Figure 4.2.2
IPL Apportionment and Crude Oil Shut-In
000 m^3/d



4.3 Trends in Crude Oil Production

Figure 4.3 illustrates the percentage change in crude oil production levels on a year-over-year basis, and highlights the composition of these changes, in absolute terms, since 1980. Canadian crude oil production has been increasing since 1981. Between 1981 and 1986 most of the additional production was exported, whereas domestic refinery demand declined. Over the past two years, however, both exports and domestic demand registered increases reflecting deregulation, fewer pipeline constraints and some growth in petroleum product consumption.

Figure 4.3
Composition of the Annual Changes in Crude Oil Production



4.4 Long Term Oil Supply Forecast

In late 1988 and early 1989 the National Energy Board (NEB) and the Alberta Energy Resources Conservation Board (ERCB) released new long term oil supply forecasts. Despite oil price uncertainties, both forecasts are more optimistic than previous reports, published in 1986 in the case of the NEB, and in 1985 by the ERCB.

The NEB outlook is part of a larger forecast entitled "Canadian Energy Supply and Demand 1987-2005", while the ERCB forecast entitled "Alberta Oil Supply 1988-2003", covers oil supply for Alberta only.

The first part of this review compares the NEB and ERCB forecasts for Alberta only. The second part describes total Canadian oil supply as forecast by the NEB. A "total Canada" ERCB supply forecast was derived by adding NEB estimates for regions other than Alberta to the ERCB Alberta forecast. In the final part of this review the need for major pipeline expansions is assessed based on the above-mentioned supply projections and, for the most part, NEB demand estimates.

i) Comparison of NEB and ERCB Supply Forecasts for Alberta

As part of its report the ERCB carried out a major geological review of Alberta's sedimentary basins, and increased the initial established reserves of Alberta conventional crude oil by 7%, to 3.3 billion cubic metres. The NEB also projected higher reserve additions than in the 1986 report, as a result of higher estimates of technical potential and more rapid resource development. In addition, government-sponsored drilling exploration and development incentives and a reduction in industry operating costs, particularly for bitumen and synthetic production have stimulated exploration above levels forecast in the 1986 report.

The respective forecasts are based on the following price scenarios in U.S. dollars for WTI (constant $ 1987).

	NEB		ERCB	
	Low Case	High Case	Low Case	Base Case1
	($/bbl)			
1988	15.00	20.00	16.00	19.00
1990	15.00	22.00	13.00	20.00
1995	16.00	27.00	12.50	23.50
2000	18.00	30.00	15.00	28.00
2005	20.00	30.00	15.00	28.00

The NEB's price projections are based on an assumed relationship between oil prices and economic growth. Based on this assumption, high economic growth and high oil demand should result in high oil prices; the converse was assumed in the low price scenario.

In contrast to the NEB forecast, the ERCB took a more traditional approach in establishing its price scenarios. According to the ERCB, high oil prices (Base Case I) can be maintained under the following circumstances:

- complete or at least improved cooperation among OPEC members with a commitment to respect quotas;

- continued increase in U.S. demand, relative to U.S. supply, with corresponding growth in U.S. net imports;

- financial support to developing countries to pay for oil imports; and

- no significant impact of alternative energy sources on the energy market share of oil.

This scenario would entail an average real crude price increase of about 4% a year for the forecast period.

The ERCB medium case (Base Case II) is somewhat less optimistic, but assumes that OPEC members solidarity is necessary to maintain reasonably high prices (a 3% increase in real prices per year). Since Base Case II is similar to Base Case I, the comparative analysis will focus on the high (Case I) and low scenarios to simplify the presentation.

Under the low case, which was developed as a reflection of the recent weakness in oil prices, the main assumptions are:

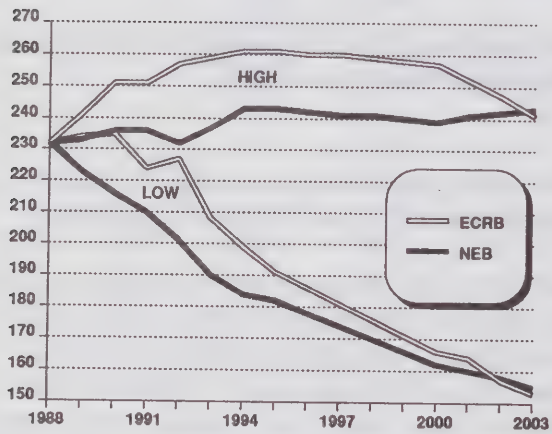
- OPEC would no longer be able to restrain production among members.

- Oil supply elasticity would be such that significant additional long-term production would occur at prices in the range of $US 17-20/bbl.

- Only in the latter part of the 1990s, when supply becomes scarce relative to demand, do prices increase.

Total Alberta supply in the ERCB high case is expected to peak at 263 000 m^3/d in the late 90's and then decline to 241 000 m^3/d by the end of the forecast period. Despite a higher price scenario, the NEB projection of total Alberta crude oil supply is expected to be generally lower than that of the ERCB and should peak in 1995 at 243 000 m^3/d and then gradually decline thereafter. With the exception of bitumen supply which is mainly driven by high prices, supplies for all other categories (conventional light and heavy, synthetic and pentanes plus) are lower under the NEB's forecast, in particular conventional heavy crude oil.

Figure 4.4.1
Forecast Alberta Crude Oil Productive Capacity
000 m^3/d



Under both NEB and ERCB low cases, total supply is forecast to peak in 1989 at 223 000 m^3/d and 234 000 m^3/d respectively and then decline to 155 000 m^3/d, and 153 000 m^3/d in 2003. This lower output, relative to the high cases, is attributable to lower bitumen production and a substantial reduction in conventional drilling activity because of reduced cash flow.

Light Crude Oil Supply

The table on the right illustrates the outlook for light crude oil and equivalent.

Table 4.4.1
Forecast Supply of Alberta Light Crude Oil & Equivalent

	1988	1989	1990	1995	2000	2003
	Actual	------------	Forecast	------------		
			(000 m^3/d)			
Conventional						
Low						
NEB	136	130	121	91	68	56
ERCB	136	136	131	96	70	59
High						
NEB	136	135	129	103	77	66
ERCB	136	139	138	113	84	70
Synthetic						
Low						
NEB	32	31	31	35	35	35
ERCB	32	32	33	36	36	40
High						
NEB	32	31	31	35	58	58
ERCB	32	32	33	41	65	67
Upgrader*						
Low						
NEB	--	--	--	--	--	--
ERCB	--	--	--	--	--	--
High						
NEB	--	--	--	--	10	10
ERCB	--	--	--	--	4	6
Pentanes Plus						
Low						
NEB	19	18	17	16	18	19
ERCB	19	19	22	22	22	21
High						
NEB	19	18	18	18	17	20
ERCB	19	19	22	22	22	21
Total						
Low						
NEB	187	179	169	142	121	110
ERCB	187	187	186	154	128	120
High						
NEB	187	184	178	156	152	154
ERCB	187	190	193	176	175	164

* *The Bi-Provincial (Husky) upgrader is deemed to be in Saskatchewan.*

Under the ERCB high case, conventional light crude oil supply is expected to decline by almost 50% to 70 000 m^3/d by 2003. Supply from established reserves will decline at a rate of about 10% a year over the next 10 years, and could reach as low as 30 000 m^3/d by 2003. New discoveries and additions, which are more price sensitive than established reserves, should peak in 1995 at 45 000 m^3/d.

The decline in conventional supply in the NEB forecast is slightly greater, at about 55% by 2003; however, new discoveries and additions are expected to be marginally higher than the ERCB by 1995. The supply situation is not as pessimistic as that published in the 1986 report. Most of the differences between the two reports reflect larger technical potential in oil drilling activity and the more rapid resource development in the 1988 report. Approximately two-thirds of the reserve additions will be as a result of new discoveries and the extension of current established reserves other than from enhanced recovery. The rest of the improvement represents an increase in established reserves through enhanced recovery.

Under both low price scenarios, reduced cash flow will force industry to reduce drilling activity substantially. Therefore, conventional light crude oil supply should drop to 56 000 m^3/d and 59 000 m^3/d for the NEB and ERCB respectively. This supply should account for approximately 36% of total Alberta light crude oil supply by 2003, in comparison with 73% in 1988.

Both forecasts and both price scenarios include the Syncrude expansion (the CAP project completed in 1988) and the Suncor debottlenecking project (by 1993). Each should add about 3 000 m^3/d to synthetic crude oil supply. Under the high case the NEB is estimating that three integrated mining projects will be added to synthetic supply (by 1996, 2000 and 2004). It should be noted, however, that these projects do not necessarily mean new plants, but could also represent expansions of existing plants. Despite a lower price scenario, ERCB synthetic supply appears to be substantially more optimistic, starting in 1995, with the gap widening to 6 000 m^3/d by 2000. Therefore, total mining plant supply is expected to more than double from the 1989 level of 31 000 m^3/d in both high-price forecasts. With respect to upgrading, the NEB is assuming that one upgrader will come on stream in 1998 with a capacity of 10 000 m^3/d, while the ERCB has it near to completion by 2003, at an output of 6 000 m^3/d.

Under both low cases, additional upgraders are not considered to be economically viable. The ERCB low case scenario predicts that synthetic production will reach 40 000 m^3/d by the end of the forecast period while NEB maximum output will peak in 1992 at 35 000 m^3/d, and then remain steady.

Pentanes plus availability, under both projections, is directly related to the volume of natural gas sales. Nevertheless, the ERCB's forecast is slightly more optimistic. Total supply could reach 22 000 m^3/d by 1992.

As previously mentioned, Alberta light crude oil and equivalent supply declines under all four projections, although the drop is less than forecast by these agencies two or three years ago. In the high cases, light crude supply in 1995 is 33% higher than forecast by the NEB in 1986, while ERCB light crude oil availability is about 4% higher than the 1985 forecast. (Conventional crude is 35% higher, but synthetic crude is 40% lower.)

Heavy Crude Oil Supply

The table below illustrates the outlook for conventional heavy and bitumen crude. (Upgraded heavy production is included in the light crude section.)

Conventional heavy crude oil supply is expected to decline substantially in all scenarios. The ERCB's reserve additions forecast is much more optimistic than the NEB projection, with supply doubling to 12 000 m^3/d by 2003.

Table 4.4.2
Forecast Productive Capacity of Alberta Heavy Crude Oil

	1988 (Actual)	1989	1990	1995	2000	2003
		(Forecast) (000 m^3/d)				
Conventional*						
Low						
NEB	25	19	17	12	9	7
ERCB	25	24	24	21	16	13
High						
NEB	25	21	20	15	10	8
ERCB	25	25	26	26	19	16
Bitumen *						
Low						
NEB	20	25	30	30	32	38
ERCB	20	23	25	24	22	20
High						
NEB	20	28	38	72	77	81
ERCB	20	26	32	59	63	61
Total						
Low						
NEB	45	44	47	42	41	45
ERCB	45	47	49	45	38	33
High						
NEB	45	49	58	87	87	89
ERCB	45	51	58	85	82	77

** Excludes volumes upgraded*

Bitumen supply, in the NEB low case, is expected to rise by 5 000 m^3/d, to 30 000 m^3/d, from 1989 to 1990, reflecting the completion of projects currently underway. During the 90's, however, bitumen supply should remain virtually unchanged until the end of the decade before rising again by 2003 as prices approach $20/bbl. As mentioned previously, bitumen is the only crude type for which the ERCB supply forecast is less than the NEB's. This lower output is directly related to a substantially lower price scenario, (only $US 15/bbl by 2003). Bitumen projects are considered to be economically viable by the industry at around $US 18 to 20/bbl. Also, cash flow problems and financial viability will evidently delay several projects, unless a technological breakthrough occurs during the forecast period. Therefore, the bitumen supply is expected to peak at 26 000 m^3/d by 1991 and then gradually decline to 20 000 m^3/d by 2003.

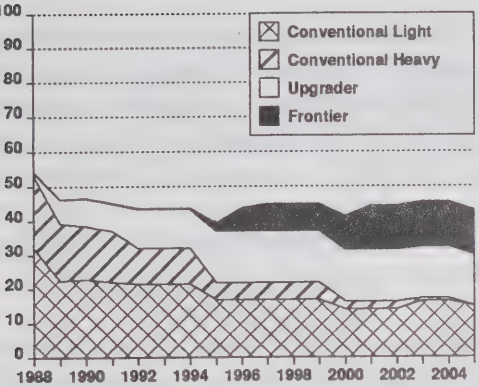
Under the high case, NEB bitumen supply, after deducting 10 000 m^3/d as feedstock for an upgrader (in 1998), should increase to 81 000 m^3/d by 2003 from 20 000 m^3/d in 1988. Despite a lower high price scenario, ERCB bitumen crude oil supply is still expected to be more than triple the 1988 level, at 63 000 m^3/d by 2000. The increase reflects the completion of new plants and project expansions. According to the NEB, in order to reach the expected supply level, it is necessary to assume an expansion of current pipeline capacity (see following section) and further development of offshore markets.

In sum, because the ERCB is more optimistic than the NEB on light crude, total Alberta oil supply is higher throughout much of the 15-year period. By the end however, the forecasts come together because the NEB is forecasting greater heavy crude supply.

ii) Crude Oil Supply Outside Alberta

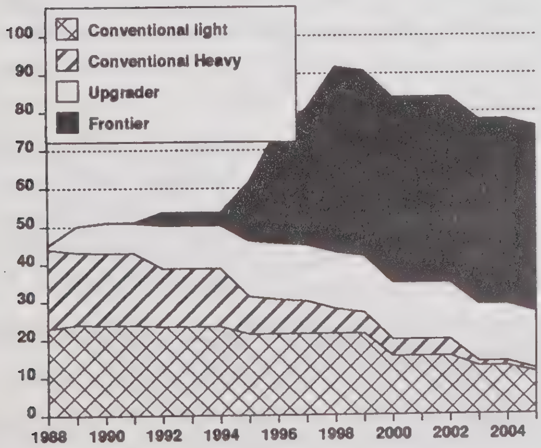
The NEB also forecast supply from areas outside of Alberta which are presented in figure 4.4.2 and 4.4.3 for the low and high case.

Figure 4.4.2
Supply Outside Alberta
(Low Case)
000 m^3/d



With regard to frontier resources, under the low case, development of these resources is expected to be less economically attractive; therefore, only some small pools in the Grand Banks and Scotian shelf areas would be produced (from floating platforms). The Amauligak development, in the Mackenzie-Beaufort Sea area, would not proceed in the forecast period; however, pipeline construction could take place in the last few years of the projection. Upgrader projects outside of Alberta such as the Newgrade upgrader will add 7 000 m^3/d starting in January 1989, and will be at capacity (8 000 m^3/d) by 1990. In addition, 7 000 m^3/d of synthetic crude will be available from the "Bi-Provincial" upgrader scheduled for completion in 1992.

Figure 4.4.3
Supply Outside Alberta
(High Case)
000 m^3/d

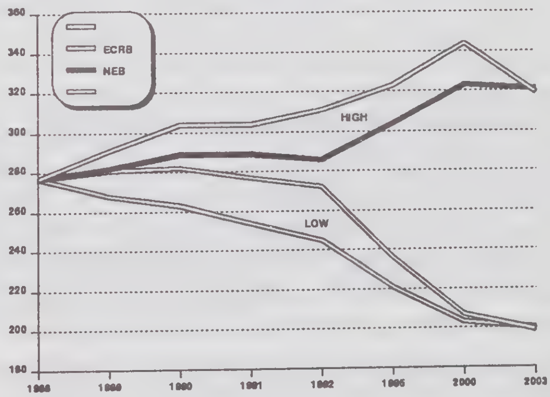


Under the high case, both the east coast offshore and MacKenzie-Beaufort Sea areas are economically viable. Production from the east coast offshore field should start in 1992 and reach its peak of 28 000 m^3/d in 1996 and then decline to a plateau of 25 000 m^3/d. With regard to production from the MacKenzie-Beaufort sea area, the mode of transport is a major issue. Initially, production of around 2 000 m^3/d is projected to start in 1990, and would be shipped from Amauligak to the Canadian west coast or the Pacific rim. A pipeline to Alberta is projected in 1997 and production could reach 24 000 m^3/d by 1999.

Total Canada

For illustrative purposes, the NEB forecast for total Canada is compared to the ERCB forecast, adjusted for the rest of Canada (figure 4.4.4). The NEB is predicting that total available supply will peak at 325 000 m^3/d by 2000 and then decline marginally to 320 000 m^3/d. The "theoretical" ERCB forecast is slightly more optimistic.

Figure 4.4.4
Forecast Total Canada Crude Oil Supply
000 m^3/d

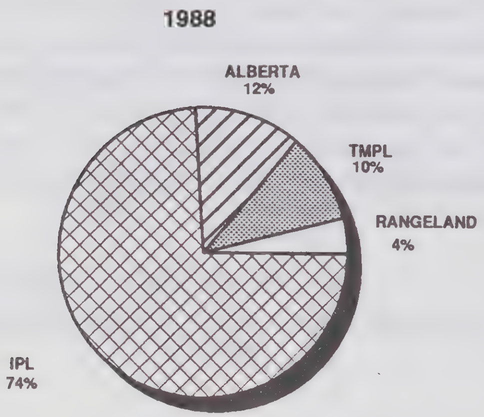


iii) Pipeline Expansion

Interprovincial Pipe Line (IPL) operates the largest oil pipeline system in the western hemisphere stretching from Norman Wells, NWT to Montreal, Quebec.

As illustrated in figure 4.4.5, in 1988 74% of western Canadian liquid hydrocarbon production was delivered on the IPL system, to the U.S. Midwest markets and to Canadian markets east of Alberta. In mid-1987, the third and final phase of IPL's expansion program (1985-1987) was completed. The capacity of the system was increased, in three stages, by almost 52 000 m^3/d, at a total cost of $350 million. Despite these expansions, IPL remains slightly short of adequate capacity (see section 4.3 for more details).

Figure 4.4.5
Disposition of Canadian Crude Oil



The Trans Mountain pipeline, from Edmonton to Vancouver, is the second largest pipeline in Canada, transported 10% of Canadian crude oil production in 1988. As discussed in previous issues, work is currently underway on the Trans Mountain pipeline which would accommodate the movement of up to 6 000 m^3/d of blended bitumen, by 1990 at a cost of $52 million. The Rangeland system was used to transport 4% of production with most of it shipped to Montana refineries.

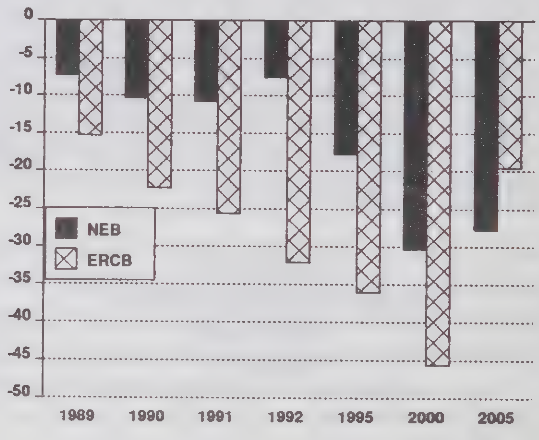
In May, 1988 IPL and Trans Mountain both announced tentative plans for major expansions, at estimated costs of $800 million and $500 million, respectively. Each company would add about 32 000 m^3/d and 30 000 m^3/d, respectively, of additional capacity by the early 1990s, by looping and/or with additional lines.

In the past, the need for pipeline expansions has been based on a long range pumping forecast developed in consultation with the producing industry. One reason the ERCB prepared its long-term outlook in 1988 was to assist government and industry in evaluating the long-term needs for additional transportation capacity.

Based on the four oil supply scenarios it is possible to get some perspective on future pipeline capacity requirements. On the demand side, most of the assumptions are based on the NEB "Canadian Energy Supply and Demand 1987-2005". Appendix III outlines the major demand assumptions. Appendix IV provides more details on the two "extreme" cases - the ERCB high and the NEB low.

Based on these supply and demand assumptions, under the NEB and ERCB high cases one can conclude that additional pipeline capacity would be required in the 1990's.

Figure 4.4.6
IPL Pumping Reserve
(High Cases)
000 m^3/d



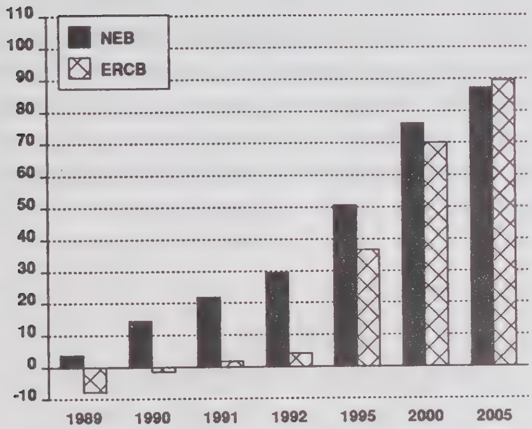
Under the NEB high case, however, a pipeline expansion will not be necessary until 1995 when additional synthetic crude oil and Beaufort Sea oil production come on stream, creating a throughput shortfall of 18 000 m^3/d. This shortfall will continue to widen to 30 000 m^3/d by 2000, as more bitumen projects are completed, and then decline gradually to 27 000 m^3/d by 2005.

A pipeline expansion would be required immediately, in the ERCB high case. The pipeline capacity deficit is ex-

pected to grow from 15 000 m^3/d in 1989, and peak at 46 000 m^3/d by 2000, before declining to 20 000 m^3/d as a result of a drop in bitumen and conventional crude oil (light and heavy) supply.

In the low cases, given the projected decline of conventional supply and unattractive prices for mining plants, and frontier and bitumen developments, it is difficult to envisage the need for any expansion.

Figure 4.4.7
IPL Pumping Reserve
(Low Cases)
000 m^3/d



For the short term, even the high cases appear to be overly optimistic. A more recent short-term NEB forecast, which takes into consideration the crude price weakness in the latter half of 1988, has total Canadian crude oil supply in 1989 at 275 000 m^3/d, 13 000 m^3/d below the ERCB long-term forecast. Relative to the long term forecast, these reductions are significant and put any pipeline expansion before the mid-1990's in question. (If crude oil prices firm up however, this situation could be reversed relatively quickly.)

There are other important factors however, which must be considered in the study process. Oil producers may wish to assume some level of "insurance premium", given the risks associated with supply forecasts. Throughout much of the 1980s, crude productive capacity was underestimated leading to a lack of transportation capacity and subsequent shut-in productive capacity. According to industry associations, since 1985 inadequate pipeline capacity cost producers up to \$1.1 billion in lost revenue.

On the other hand, assuming the \$800 million expansion proceeds, if the anticipated crude oil supply does not materialize, then shippers could be faced with an incremental tariff of \$0.50/bbl. This is to be compared with an incremental tariff, of around \$0.30/bbl, if the supply is adequate. In either case producers would pay for the expansion.

Some of the other risk factors that may need to be assessed, particularly in the medium-term, include seasonal demand variations, changes in Alberta demand and the possibility of no heavy crude exports via Trans Mountain.

Current Status

After having reviewed the oil supply forecasts prepared by the NEB and ERCB, there is a growing consensus among producers and marketers that any immediate major pipeline capacity expansion should be deferred. By the time any expansion could be completed, the need for it would be past. If frontier (Beaufort) developments proceed at some point in the future, there would be sufficient lead time to expand southern pipeline capacity as required. The current oil price instability has compounded companies' unwillingness to see any further reduction in well-head prices. Some relatively modest improvements to the IPL system may still be undertaken if the costs are reasonable.

Interhome Energy Inc., which owns the IPL system, is reviewing the need for future pipeline expansions in light of lower oil prices and general cost cutting now occurring in the oil industry. Interhome is currently reviewing "cheaper" alternatives to the \$800 million, 25 000 m^3/d expansion proposal. These include adding shorter sections of pipeline, exploring other transportation routes, and further "dilution" of heavy crudes. Interhome will continue to work closely with oil producers. Trans Mountain is also reviewing its proposed expansion in this context.

5. Exports and Imports

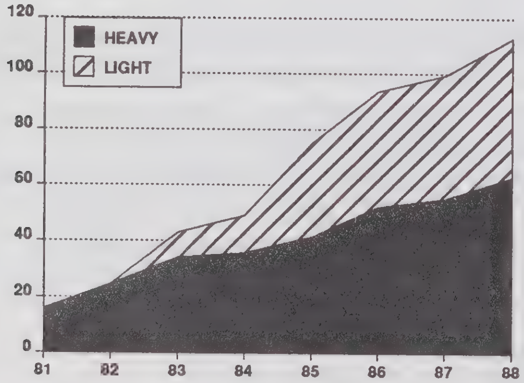
- *Crude oil exports in 1988 jumped by 14% to 113 000 m^3/d, representing the highest volume exported since 1974. In 1989, Canadian crude oil availability is forecast to remain unchanged, which may reduce the export potential.*

- *Both crude oil imports and the net product trade surplus increased; however, most of the growth was related to the reactivation of the Come-by-Chance refinery.*

5.1 Crude Oil Exports

Total crude oil exports in 1988 jumped by 14% to 113 000 m^3/d, with the incremental exports split 40:60 in favour of heavy crude oil. Total exports represented 41% of total Canadian crude oil production, up almost 4 percentage points from last year. As a result of an increase in both domestic and export demand for Canadian crude, up 5 000 m^3/d and 14 000 m^3/d respectively, an upstream crude inventory drawdown was necessary, as Canadian crude oil production rose only 11 000 m^3/d. These increases reflect the strength of both the Canadian and American economies and some additional pipeline capacity to U.S. markets. Much of the increase in exports occurred during the first half of the year. In the second half, exports rose 11% reflecting slower growth in crude oil production (as a result of lower prices), and higher domestic demand.

Figure 5.1.1
Crude Oil Exports
000 m^3/d



Light and equivalent crude exports accounted for 45% of total exports, virtually unchanged from last year, and averaged 50 000 m^3/d, up 14% from a year ago. Chicago - area refiners took most of the incremental volume. Exports of heavy crude oil totalled 63 000 m^3/d, up 8 000 m^3/d and represented 81% of production, up 7 percentage points from last year.

Despite an increase of almost 2 000 m^3/d in offshore exports, mainly to Taiwan and South Korea, 98% of Canadian crude oil exports were to the United States. PADD II remained the major destination for Canadian crude oil, accounting for three-quarters of the market and two-thirds of the growth over last year.

Canadian producers continue to search for new destinations. Reflecting this market diversification effort, crude oil exports to PADD I and III rose by 1 500 m^3/d and 1 000 m^3/d, to 10 000 m^3/d and 2 000 m^3/d, respectively. Out of the total volume, approximately 3 000 m^3/d and 1 000 m^3/d respectively were tankered through the ports of Montreal and Vancouver. In total, 6 500 m^3/d or 6% of Canadian crude oil exports were delivered by tanker.

Table 5.1.1
Crude Oil Exports by Destination

	Light		Heavy		Total	
	1987	1988	1987	1988	1987	1988
	(000 m^3/d)					
United States						
PADD I	7.0	7.8	1.6	2.2	8.6	10.0
PADD II	27.7	32.2	48.2	53.0	75.9	85.2
PADD III	0.0	0.0	0.8	1.7	0.8	1.7
PADD IV	7.4	7.5	3.3	3.5	10.7	11.0
PADD V	1.8	1.9	0.4	0.5	2.2	2.4
Total U.S.	43.9	49.4	54.3	60.9	98.2	110.3
Offshore	0.3	0.7	0.3	1.7	0.6	2.4
Total Exports	**44.2**	**50.1**	**54.6**	**62.6**	**98.8**	**112.7**

PADD IV remains Canada's second largest U.S. market (Montana and Wyoming area) with total deliveries of 11 000 m^3/d which indicates that Rangeland pipeline system operated almost at capacity.

According to the U.S. Department of Energy, total U.S. crude oil imports in 1988 averaged 795 000 m^3/d, an increase of 66 000 m^3/d or 9%, from a year ago. Saudi Arabia remained the largest supplier of crude to the United States with 18% of the import market, followed by Canada at 14%. Crude oil imports, as a percentage of total U.S. refinery crude oil demand (including domestic inputs) amounted to about 40%. The Canadian share of total demand was slightly over 5%.

1989 Outlook

Based on refiners' estimates of demand for Canadian domestic crude in 1989, and assuming no shut-in, and no inventory drawdown or build, total Canadian crude oil exports could decline by as much as 14% to 97 000 m^3/d. This potential decline reflects a forecast increase of 7% in domestic demand for Canadian crude oil, whereas crude oil production is estimated to remain unchanged from 1988. The reduction in exports also assumes that Canadian refiners want and will get all the crude demanded. More realistically, one would expect that part of the incremental demand will be met by additional imports into Montreal and into Ontario via the U.S. mid-continent pipeline system.

With regard to the crude type, despite a marginal increase in heavy crude oil production, exports are expected to drop by 14% to 54 000 m^3/d, reflecting a substantial jump (over 60%) in Canadian demand. Most of this increase is attributed to the start up of the Newgrade upgrader and the corresponding switch in refinery feedstocks (around 8 000 m^3/d) from light crude to conventional heavy crude oil. Despite this shift from light to heavy crude and relatively stable demand for light crude, light exports could fall by 13% to 45 000 m^3/d, reflecting a drop in light crude oil supply. In either case, it appears that exports will have peaked in 1988, at least for the short-term.

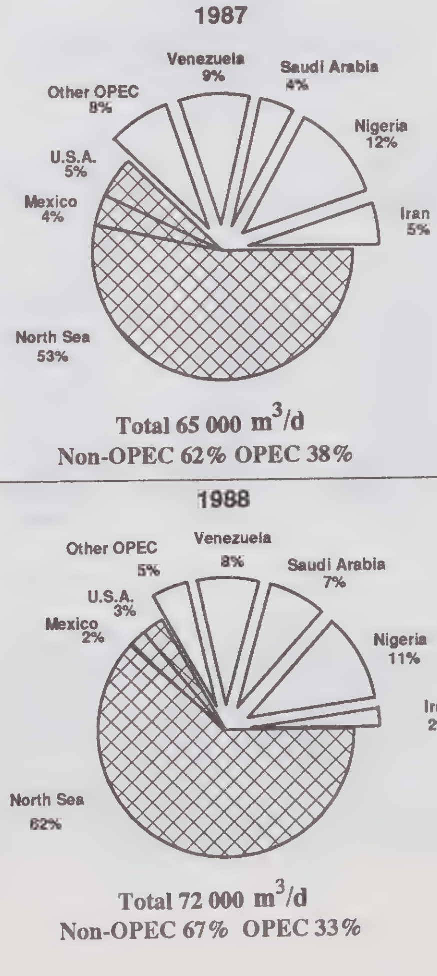
5.2 Crude Oil Imports

In 1988, crude oil imports averaged 72 000 m^3/d, an increase of 7 000 m^3/d, or 11% from a year ago. Most of the increase was attributable to the reactivation of the Come-by-Chance refinery late in 1987. Imports from most countries declined; however, supply from North Sea and Saudi Arabia increased and accounted for two thirds of total imports.

OPEC-supplied crude oil was slightly lower in volumetric terms, at 23 500 m^3/d. The cartel's market share fell by 5 percentage points to 33%. Imports from Saudi Arabia, however, almost doubled to 5 000 m^3/d, making that country the third-largest OPEC supplier after Nigeria (7 500 m^3/d) and Venezuela (5 500 m^3/d). Imports from Iran, fell by 50% to 1 500 m^3/d, with all deliveries occurring during the second and third quarters of 1988. Nevertheless, imports from OPEC Middle East countries remained unchanged in percentage terms, at 40% of total OPEC supply.

Non-OPEC crude receipts rose by 20% to 48 000 m^3/d. The North Sea was the only non-OPEC source of supply to register an increase, up 30% to 44 000 m^3/d and represented 62% of total Canadian foreign receipts. Imports from both Mexico and United States fell by about 1 000 m^3/d, to 1 500 and 2 000 m^3/d respectively.

Figure 5.2.1
Sources of Crude Oil Imports

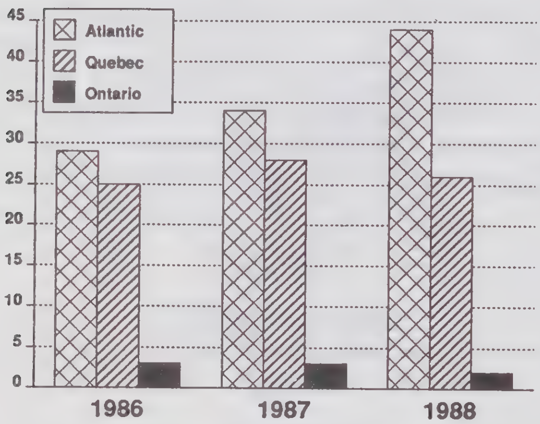


Mainly because of import/export processing agreements in eastern Canada, crude oil imports in 1988 represented 30% of total Canadian crude oil receipts, the highest level since 1977, when imports accounted for 34%.

Imports fell by 5% to 68 500 m^3/d during the fourth quarter 1988 representing the first year-over-year decline since 1984. This decline is related to the dissipating impact of the Come-by-Chance refinery which started operation late in the third quarter of 1987, and a significant crude oil inventory drawdown in the Atlantic. All the decline occurred in OPEC crude oil.

On a regional basis, imports into the Atlantic region in 1988 averaged almost 44 000 m^3/d, up 27% and accounted for 60% of total foreign receipts. Despite an increase of 3% in total crude oil receipts, Quebec imports fell by 6% to 26 000 m^3/d, reflecting increased use of domestic crude oil. Imports into Ontario declined by 500 m^3/d to 2 000 m^3/d.

Figure 5.2.2
Crude Oil Imports by Region
000 m^3/d



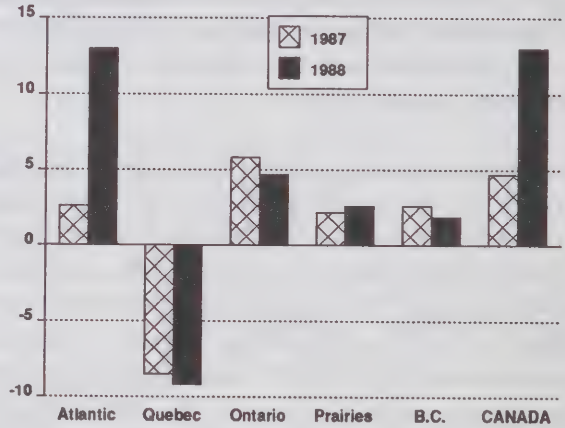
Imports have risen each year, since 1985. Greater product export opportunities in the northeastern U.S. have accounted for about half of the increase, while the removal of federal subsidies (in 1985) for domestic crude transfers to refineries in eastern Canada, increased petroleum product consumption, and IPL pipeline bottlenecks, have accounted for the balance.

It appears that imports have now reached a plateau and are expected to increase only marginally during the next few years, barring unforeseen declines in western Canadian light crude oil supply or further product export opportunities.

5.3 Petroleum Product Trade

As a result of a sharp increase in product exports, the net product trade surplus almost tripled in 1988 to average 13 000 m^3/d. This increase primarily reflects the reactivation of the Come-by-Chance refinery which operates under a crude import and product export agreement.

Figure 5.3.1
Net Petroleum Product Trade
000 m^3/d

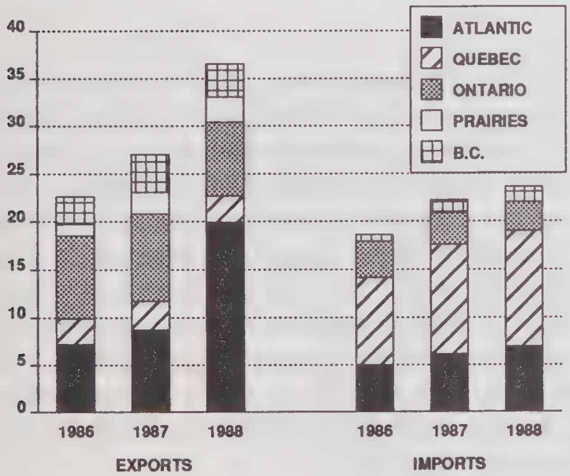


The Atlantic region recorded the largest trade surplus at 13 000 m^3/d, in comparison with less than 3 000 m^3/d in 1987. Quebec remained the only region to register a product trade deficit, at 9 000 m^3/d, marginally higher than last year's level. It is interesting to note that the Quebec deficit offset the trade surplus recorded in the regions west of Quebec. In total, the surplus in petroleum product trade accounted for 5% of refinery throughput in Canada.

Gross petroleum product exports in 1988 rose by 34% from 1987, to 36 500 m^3/d, and accounted for 15% of refinery throughput. Despite a substantial decline during the fourth quarter as a result of a major refinery turnaround at Come-by-Chance, exports from the Atlantic region reached 20 000 m^3/d, more than double last year's level. In addition, they accounted for over 50% of total product exports in Canada, with motor gasoline accounting for two thirds.

Ontario was the second largest exporter, with one fifth of total exports but recorded a slight decline (1 000 m^3/d) reflecting an increase of 3% in petroleum product consumption. Approximately, 30% of Ontario's exports were heavy fuel oil, despite an increase of 12% in domestic sales. Exports from the Prairies remained steady at 2 500 m^3/d whereas exports from British Columbia fell by 13% to 3 500 m^3/d reflecting increased competition in the west coast market.

Figure 5.3.2
Gross Product Exports/Imports
000 m^3/d



Gross petroleum product imports in Canada in 1988 averaged 24 000 m^3/d, the highest-level since 1969. Quebec, accounted for 51% of these imports, with transportation fuel representing one third of the total. During the fourth quarter, product imports into Quebec reached almost 13 000 m^3/d as a result of refinery turnaround and inventory build.

Despite total exports averaging 20 000 m^3/d, the Atlantic region is the second largest importing region, at 7 000 m^3/d. Heavy fuel oil made up three quarters of the total, reflecting high demand for thermal electricity generation and forest industry consumption. As in Quebec, imports rose sharply in the Atlantic region during the fourth quarter, up 4 000 m^3/d to 10 000 m^3/d likely reflect a desire to fill inventories for the winter before prices rose in line with crude oil.

Most of the Canadian petroleum product exports in 1988 were to the United States. In 1988, approximately 70% of total main petroleum product exports were to PADD I, up 10 percentage points from last year. Refined products produced at the Come-by-Chance refinery are almost entirely exported to PADD I. PADD II, the second most important market for Canadian products accounted for 11% of main petroleum exports, while the other three PADDs totalled less than 20%.

Table 5.3.1
Main Petroleum Product Exports
to the United States

PADD	1987	(000 m^3/d)	1988
I	13.1		22.4
II	4.2		3.5
III	---		1.6
IV	0.8		0.9
V	3.0		2.5
Total	**21.1**		**30.9**

Interregional Product Movements

In the previous edition of the Canadian Oil Market, the importance of international and interregional trade of petroleum products and its usefulness to balance refinery output to sales was discussed. Given seasonal fluctuations, regional preferences for products, and refinery configuration and centralization, interprovincial movements can provide logistical savings.

Figure 5.3.3
Interregional Petroleum Product Trade
000 m^3/d

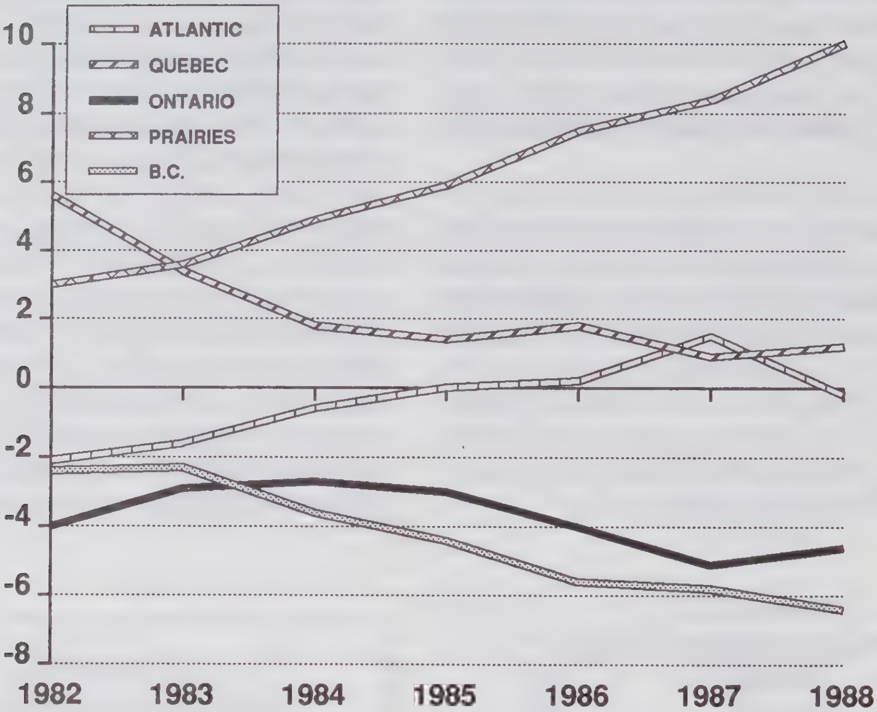


Figure 5.3.3 outlines interregional trade in Canada over the last seven years. As a result of its geographical location and relatively higher transportation costs, interregional transfers in the Atlantic region were limited, in comparison with other regions. Over the period portrayed, the region swung from a small net importer from other regions to a net exporter. In contrast, in 1988 interregional trade in the Prairies accounted for 80% of total petroleum interregional movements, reaching 10 000 m^3/d and representing 16% of crude runs in that region. The increase reflects the continuing increase in product movements (mainly partially processed oil) to British Columbia and to Ontario.

As a result, the interregional trade deficit in British Columbia has risen by 4 000 m^3/d, to 6 500 m^3/d, since 1982. Despite being a net international product importer of around 9 000 m^3/d, Quebec has recorded an interregional trade outflow of product in the range of 1 000 m^3/d to 2 000 m^3/d for the past five years, down somewhat from the early part of the period covered. In part, this was as a result of Montreal refiners supplying a significant portion of the eastern Ontario market. The opposite occurred in Ontario, where the international trade surplus of 5 000 m^3/d in 1988 was offset by an equal interregional trade deficit.

6. Energy Trade Balance

- *Energy trade surplus declines as a result of lower prices and rise in Canadian exchange rate.*

6.1 International

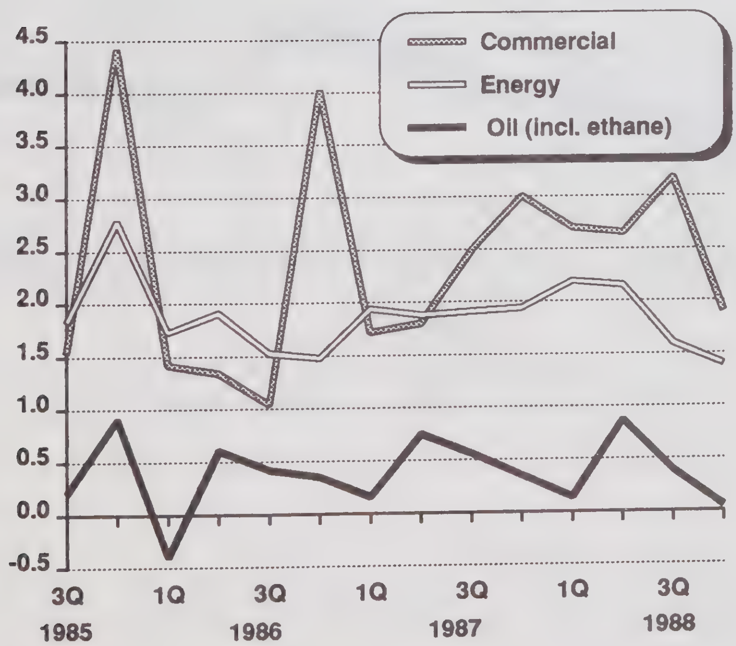
This year Canada experienced its worst overall commercial trade performance since 1981. Record levels of imports for certain commodities (i.e. machinery and equipment) and the rise in the Canadian exchange rate vis-à-vis the United States helped to reduce Canada's total trade surplus to $8.8 billion, $2.2 billion less than 1987. However, the energy trade component of this surplus faired better, registering an annual value of $7.6 billion, marginally below last years level of $7.7 billion.

As illustrated by figure 6.1, the fourth quarter of 1988 commercial trade surplus fell to $1.9 billion, down from $3.0 billion in the same quarter in 1987. Over the same period, Canada's energy trade surplus declined by almost $500 million, to $1.4 billion. As a result of the significant decline in the fourth-quarter commercial trade surplus, total energy accounted for 74% of the surplus compared with about 65% a year earlier.

Strong natural gas sales contributed $800 million to the fourth-quarter energy surplus, $150 million more than 1987. As a result of weak crude oil prices and a coincidental rise in the exchange rate, the crude oil and petroleum product surplus declined to $50 million compared with $395 million the year before. Increases in liquid petroleum gases, and uranium were more than offset by a $175 million reduction in electricity, to $110 million. This decline is attributed to increased domestic demand for electricity and low water conditions.

A marginal improvement in the commercial trade performance is predicted for the first part of 1989. Exports of energy will likely increase as a result of a forecasted improvement in world crude oil market prices.

Figure 6.1
Oil and Energy Trade Balance
$ CAN (Billions)



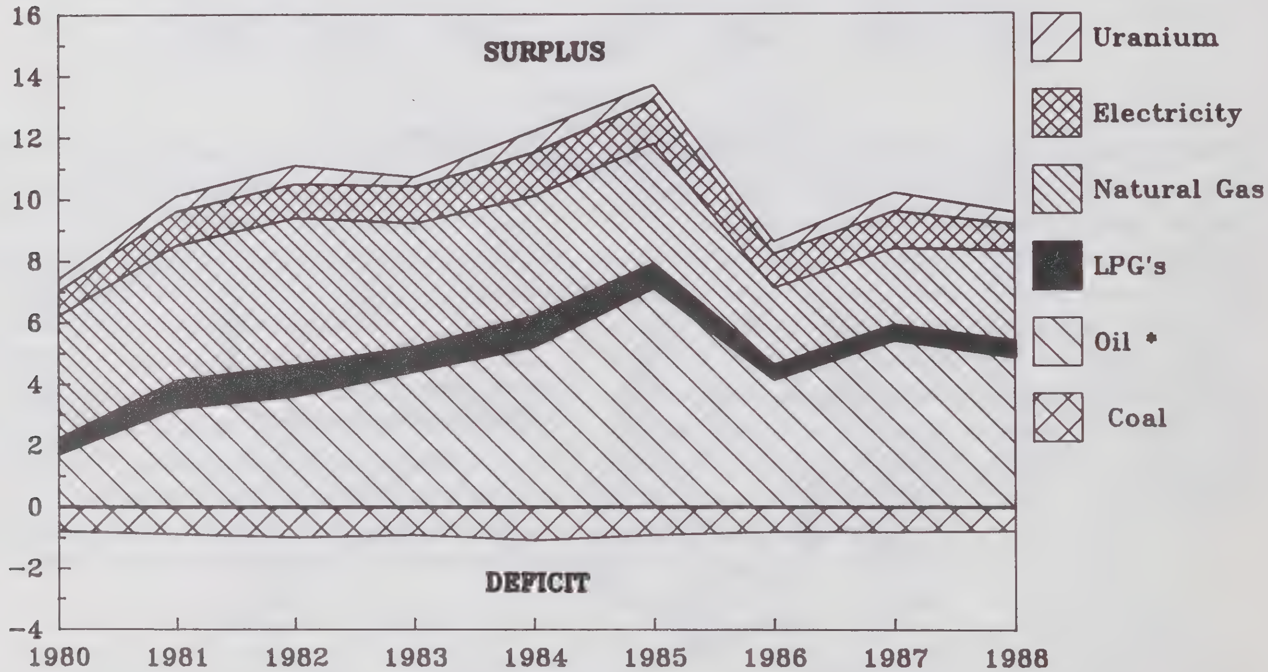
6.2 United States

Canada's energy trade surplus with the United States fell in 1988. While the annual surplus was $8.8 billion, it was almost $600 million less than in 1987, well below the record $13 billion surplus set in 1985. On a quarter basis, the fourth quarter surplus was $2.1 billion, $100 million less than the same quarter last year but almost $300 million higher than the third quarter of 1988.

Figure 6.2 illustrates that since 1980 the value of oil including petroleum products has increased. However, in 1988 the oil surplus, reflecting both weak prices and strength of the Canadian dollar, declined by $500 million to $4.8 billion. Natural gas, pushed by a 31% increase in exports, was the only energy commodity to register a substantial increase, up $400 million to $2.9 billion compared with last year.

Nevertheless, the oil surplus represented 63% of Canada energy trade surplus with the United States, up about six percentage points higher than last year. Natural gas accounted for 33% compared with 27% in 1987.

Figure 6.2
Net Energy Commodity Trade with the U.S. (Value)
$ CAN (Billions)



* *includes petroleum products*

7. Stocks

- *Although closing inventory levels were 7% below the level last year, on balance stocks were about 10% higher throughout 1988*
- *The greatest changes occurred in the Atlantic and Quebec.*

Total crude and petroleum product stocks were, on average, about 10% higher in 1988 than in 1986 and 1987. Most of the increase reflected higher consumption and an inventory build concomitant with the reactivation of the Newfoundland refinery in the fourth quarter of 1987.

During the fourth quarter of 1988 however, refiners drew down inventories significantly, with the largest portion of the decline occurring in December. As a result, closing stock levels in December were 7% below the end-December, 1987 levels. Product stocks were down 7%, to 11.1 million cubic metres, while crude inventories fell almost 8%, to 2.5 million cubic metres.

The changes in crude stocks were concentrated in the Atlantic and Quebec. In the Atlantic region stocks were drawn down at about 5 000 m^3/d during the fourth quarter, as refiners maintained refinery throughput while crude imports fell. In Quebec throughput declined; however, crude deliveries were maintained. As a result, crude stocks rose by 2 000 m^3/d.

On the product side, drawdowns occurred in both Quebec and Ontario in the fourth quarter. A rise in product exports and interprovincial trade and the 4% increase in provincial sales, relative to the year-earlier period, accounted for much of the drop in Ontario.

On a year-over-year basis the product drop was spread across all products. The large drawdown which occurred in the fourth quarter also included all products - except gasoline, which increased slightly

Figure 7.1
Closing Crude and Product Inventories in Canada

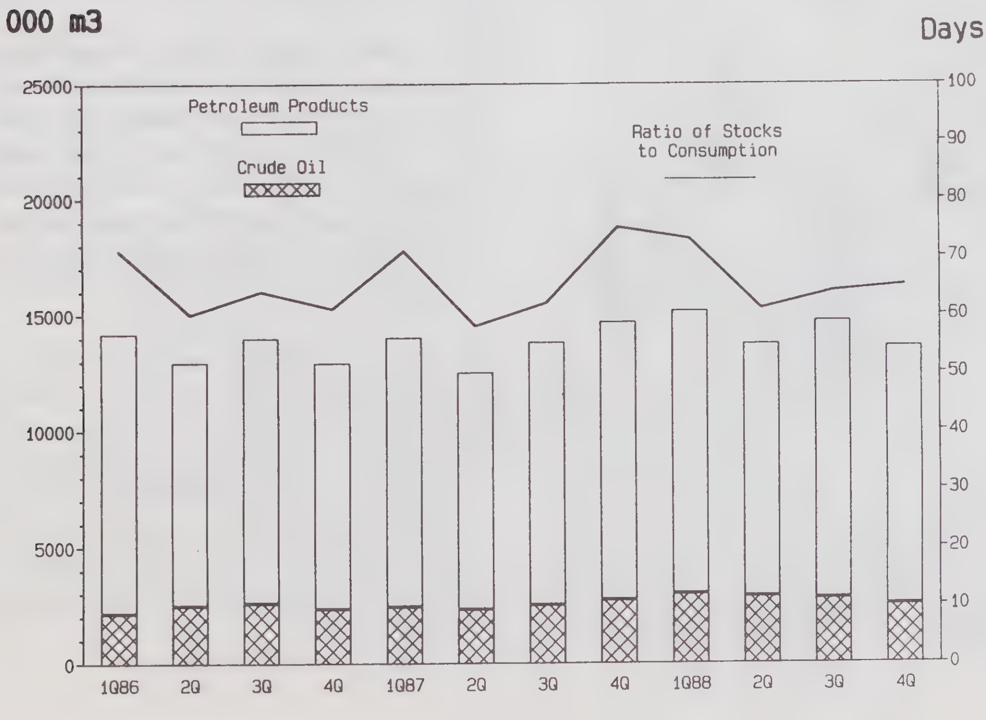


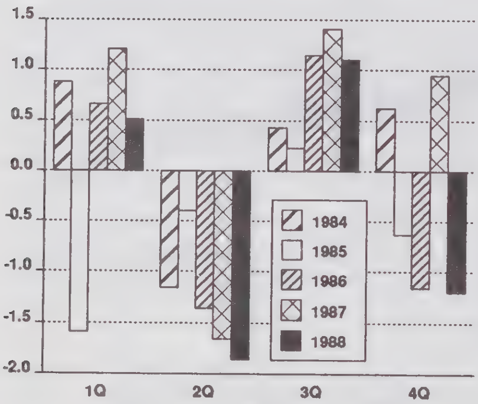
Table 7.1
Closing Inventories by Region
- December-

	1987		1988	
	Crude	Product	Crude	Product
	(000 m^3)			
Atlantic	1210	1930	745	1945
Quebec	675	2700	920	2210
Ontario	490	3600	490	3390
Prairies	200	2600	240	2400
B.C.	95	1130	75	1180
Canada	**2670**	**11960**	**2470**	**11125**

As illustrated in figure 7.2 total stock changes in both the third and fourth quarter of 1988 followed the "historical" trend. The counter-seasonal build which took place in the fourth quarter of 1987 is attributable, for the most part, to the start-up of the Newfoundland refinery.

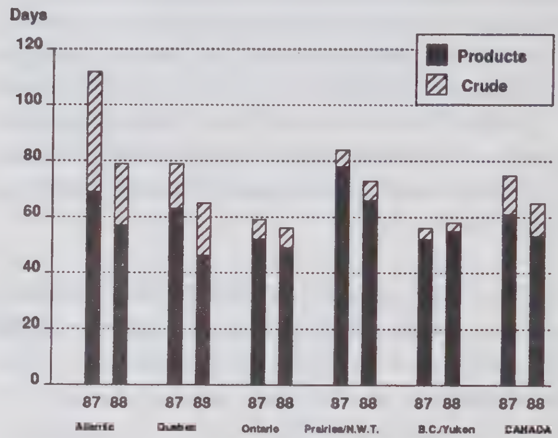
Figure 7.2
Crude Oil and Petroleum Product Stock Changes

000 m^3/d



As of December 31, 1988 the ratio of stocks to consumption at the national level was 65 days of consumption, down 10 days from the 1987 level, but still 4 days above the end-1986 level. Significant changes in stocks and sales in both the Atlantic and Quebec accounted for much of the decline.

Figure 7.3
Ratio of Stocks to Consumption
End December



In comparison with pipeline-connected markets, where crude oil can account for as little as 5% of total crude and product stocks, the crude portion of the total is generally well over 30% in the more import-dependent regions of Quebec, and in the Atlantic.

The Atlantic region is not connected by pipeline to Canadian supplies and has wider crude stock variations reflecting the timing of tanker deliveries. Furthermore, the ratio of stocks to consumption suffers by comparison to the rest of Canada because a larger portion of shipments are to the export market. Excluding the Atlantic region, the ratio of stocks to consumption for the rest of Canada was down only 6 days from 1987.

In comparison with the average days of consumption for Organization for Economic Cooperation and Development (OECD) countries, the Canadian stock level, which would include about 8 days of supply in tankage along major pipelines in Canada, compares favourably. The Canadian ratio was 73 days versus 67 days for OECD countries. Including government-controlled stocks however, the OECD number increases to 95 days.

8. Prices

- *Although crude oil prices were volatile throughout 1988, (falling by as much as 30%), as a result of rebound in the fourth quarter, WTI closed the year at about the same level as 12 months earlier - $US17/bbl.*
- *Canadian gasoline prices were down in 1988, with prices in the Prairies characterized by extreme volatility.*

8.1 International Crude Oil Prices

Developments in the world oil market during 1988 further emphasize the difficulties OPEC faces in reconciling its conflicting volume and price objectives. In 1988, it became increasingly apparent that OPEC was unable to control its overall output because of the growing difficulty of matching members' individual production targets with their revenue requirements.

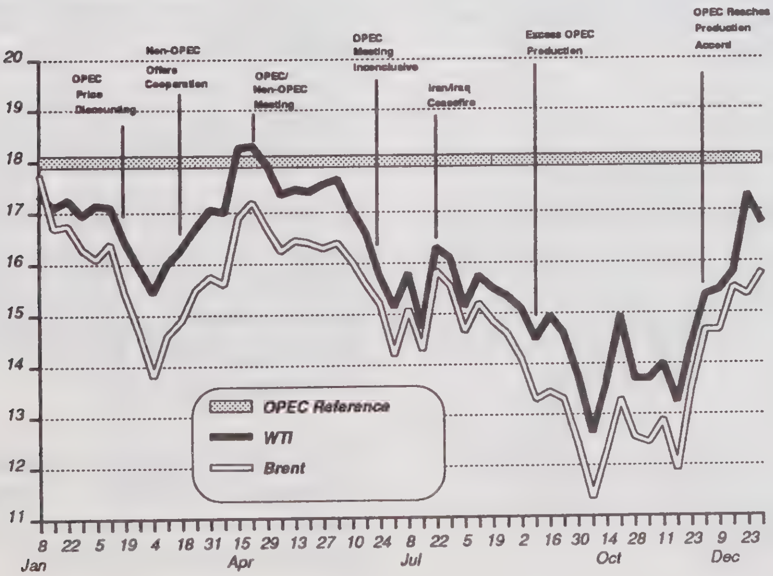
Figure 8.1 illustrates the predominately downward trend of spot crude oil prices over 1988. As can be seen, whenever OPEC seemed to be making progress in curtailing production: i.e. in April when it appeared that OPEC/non-OPEC output cooperation might be a possibility; in July with the announcement of the Iran/Iraq ceasefire; and in October as OPEC began serious committee negotiations, one or more factions within the group could not agree. The end result was an inevitable slide into price competition for market share which led to excessive production, growing inventories and price discounting. Indeed, spot WTI prices hit a two-year low in early October ($US12.55/bbl).

However, with OPEC's success in putting together the November price/production agreement, crude oil prices began to firm. Spot WTI averaged $US16/bbl in December, the highest monthly level since June. Nevertheless, OPEC must maintain strict production discipline in the first quarter of 1989 to maintain stable prices.

8.2 Domestic Crude Oil Prices

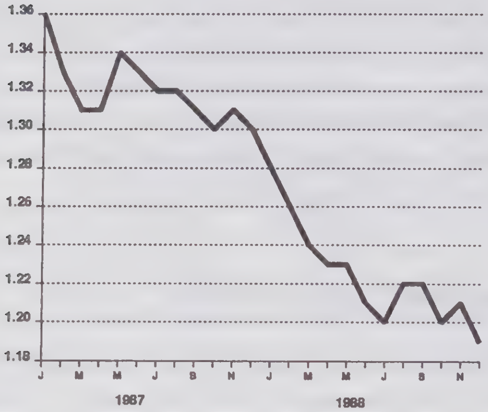
Light Canadian crude oil posted prices, during the fourth quarter of 1988, averaged $16.45 per barrel, a decrease of $1.27 from third quarter prices. The decrease in crude oil prices is primarily attributed to a world crude oil price decrease of about $CAN 1.10 per barrel.

Figure 8.1
1988 Spot Crude Oil Prices (FOB)
$US/bbl



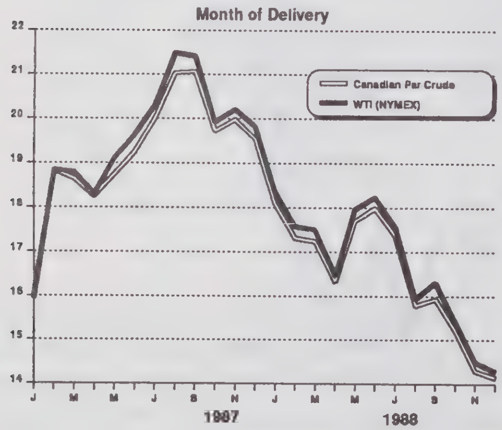
During 1988, light crude prices averaged $18.65 per barrel compared to $24.32 in 1987; the difference of $5.67 was in part caused by lower international prices (about $CAN 4.00 per barrel) and also by the strengthening of the Canadian dollar vis-à-vis the American dollar (illustrated in figure 8.2.1) which had an additional downward influence of about $1.60 per barrel.

Figure 8.2.1
Canada/U.S. Exchange Rates



Canadian light crude oil prices follow the trend set by international crudes, primarily the U.S. benchmark crude West Texas Intermediate (WTI). Figure 8.2.2 illustrates the close relationship between prices for WTI and Canadian crude, after adjustments for delivery times to Chicago. The differential between those crudes, in Chicago, dropped from $US 0.26 per barrel in 1987, to about $US 0.18 in 1988.

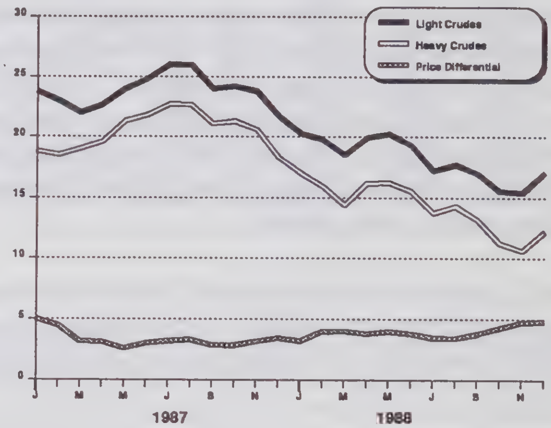
Figure 8.2.2
Canadian Par Crude vs WTI (NYMEX *)
$US/bbl



* *New York Mercantile Exchange*

Figure 8.2.3 compares actual prices for Alberta light and heavy crude oil, purchased for use in Canada at main trunk line injection stations. On average, reported light conventional crude oil quality during the third quarter of 1988 was 37.2° API, 0.4 % sulphur and blends of heavy crude were 23.9° API, 2.6 % sulphur.

Figure 8.2.3
Comparison of Domestic Light and Heavy Crudes
Actual Purchase Prices-Alberta
$ CAN/bbl



The differential between Canadian light and heavy crude prices, for the fourth quarter, was about $4.71 per barrel, more than $1.00 above the third quarter differential. The larger price differential between light and heavy crudes reflects the lower demand for heavy crude during the winter months.

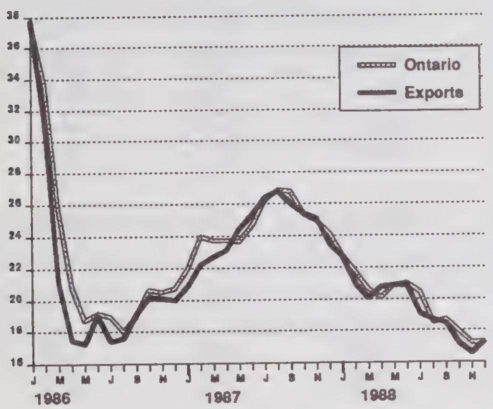
8.3 Light Crude Values: Export and Domestic

In 1988, both the value of light crude exports and deliveries to Ontario refiners fell about $5.50/bbl, from $22.75/bbl to $17.25/bbl. Throughout the year, the average value of exports was about $0.30/bbl less than Ontario acquisition costs, after adjustments for quality and transportation costs.

In October and November, the gap - in favour of exports - averaged $0.70/bbl. It disappeared in December however, when export prices rose in line with the rebound in world oil prices.

Compared with the first half of 1987, IPL pipeline capacity concerns in 1988 were only marginal. Generally, the impact on pricing was also slight. A more important factor contributing to the export advantage is the shorter delivery distance to U.S. destinations, which is particularly noticeable in markets, where prices are declining, as they were throughout most of 1988.

Figure 8.3
Domestic Light Crude Export and Ontario Domestic Acquisition Values
Equalized for Transportation and Quality
$ CAN/bbl



8.4 Petroleum Product Prices

Price Trends

Beginning with this issue, prices for regular unleaded gasoline at self-serve outlets will be used to illustrate gasoline price trends. These prices are collected weekly through Energy, Mines and Resources' Regional Offices. Previously, an average Statistics Canada full-serve and self-serve regular unleaded gasoline price was used.

The average Canadian price for regular unleaded gasoline at self-serve outlets declined by 2.8 cents per litre, or 5.6%, during 1988 (December 1987 vs December 1988).

Price trends in the 10 major centres across Canada, however, reflected two distinct patterns during the year. Centres in Atlantic Canada and Quebec experienced relatively stable prices with three specific price declines during the year. By year-end, prices were about 2.4 to 3.7 cents per litre below December 1987 price levels.

In major centres west of Quebec, where downward trends were similar to those in Eastern Canada, prices were characterized by extreme volatility. Toronto prices moved within a 5 to 6 cents per litre range as prices changed weekly. In the Prairies, price wars drove prices down by as much as 13 cents per litre for periods as long as two months. At the end of December, prices in Calgary and Regina were nearly 11 cents per litre below December 1987 levels. Vancouver also experienced several severe price wars, with declines of up to 12 cents per litre, but these were generally shorter-lived than those experienced in the Prairies, usually lasting a week or two.

Retail diesel oil prices were relatively stable in 1988. The average Canadian price declined by about 1.0 cents per litre with most major centres experiencing declines of between 0.5 and 2.5 cents per litre. In December 1988, diesel prices ranged from 36.2 cents per litre in Calgary to 57 cents per litre in St. John's, NFLD. The small volumes of diesel fuel sold at retail tend to make this market less volatile than the gasoline market.

Average residential furnace oil prices declined by 2.2 cents per litre from December 1987 to December 1988. Prices were very stable through the first eight months of 1988, with most of the declines coming at the beginning of the 1988-89 heating season.

Consumption Taxes on Petroleum Products

The federal excise tax on motor gasoline was increased by 1.0 cents per litre on April 1, 1988. The tax is currently 6.5 cents per litre on all grades of gasoline and 4.0 cents per litre on diesel oil (see Appendix VI).

Table 8.4
Average Regular Unleaded Gasoline Prices
Self-Serve
1987-1988

	1987 Dec. 29	1988 March 29	1988 June 28	1988 Sept. 27	1988 Dec. 27	% Change 12 mo.
	¢/litre					
St. John's(NFLD)	54.6	52.8	53.9	52.5	50.9	-6.8
Charlottetown	53.2	51.6	52.3	50.9	49.6	-6.8
Halifax *	51.5	49.9	50.9	49.5	47.9	-7.0
Saint John(N.B.)*	51.0	49.7	50.7	49.8	48.6	-4.7
Montreal	57.7	56.0	57.1	55.8	54.0	-6.4
Toronto	46.0	46.1	48.6	46.5	45.9	-0.2
Winnipeg	40.8	43.6	42.1	45.9	44.5	9.1
Regina	50.0	48.0	45.6	45.6	39.2	21.6
Calgary	47.8	44.2	41.1	41.6	37.0	-22.6
Vancouver	51.9	48.9	48.8	48.8	47.3	-8.9
Canadian Average	50.4	49.4	50.1	49.3	47.6	-5.6
Consumption taxes included:						
Federal	8.8	8.9	9.9	9.9	9.9	12.5
Provincial	9.4	9.4	9.8	9.9	9.8	4.3

* *Full-serve*

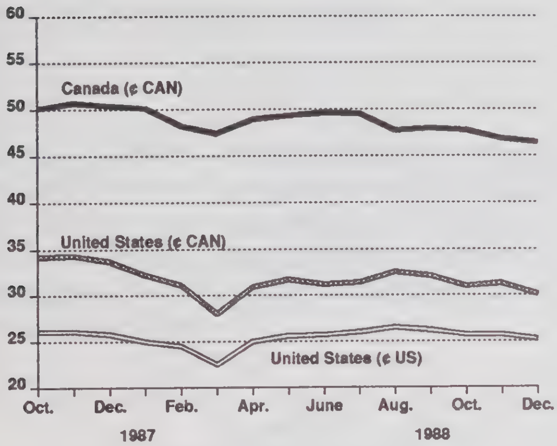
The federal sales tax on petroleum products is reviewed quarterly and adjusted according to the average Industrial Product Price Index. In 1988 these review processes resulted in a net increase of 0.1 cents per litre in the sales tax on all grades of gasoline and no change to the tax on diesel.

The average provincial sales tax on all grades of gasoline increased by 0.7 cents per litre to reach 10.1 cents per litre by December 1988. This increase is largely attributed to the rise in the surtax on regular leaded gasoline in both Ontario and Manitoba. The average provincial tax on diesel was 9.2 cents per litre in December, unchanged from a year earlier.

Canada vs United States

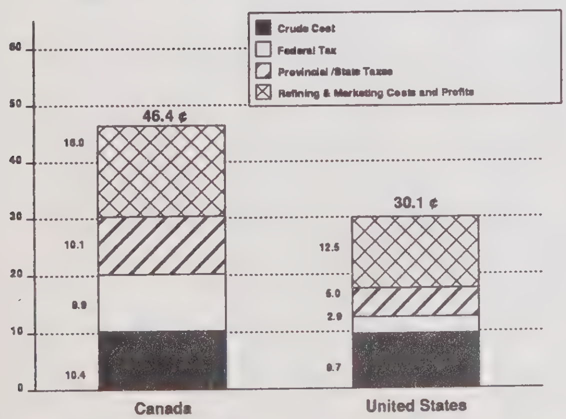
The average retail price for all grades of motor gasoline experienced a slightly larger decline in Canada than in the United States during 1988. Consequently, the difference between Canadian and American average gasoline prices was reduced from 16.7 cents per litre in December 1987 to 16.3 cents per litre in December 1988. Had the Canadian dollar not strengthened relative to the U.S. dollar, the differential would have been further reduced by 2.8 cents per litre.

Figure 8.4.1
Average Retail Price of Motor Gasoline
Canada vs United States
cents per litre



Higher consumption taxes in Canada continue to account for almost three-quarters of the price difference between the two countries. The balance is attributable to higher refining and marketing costs and/or profits in Canada.

Figure 8.4.2
Breakdown of Average Pump Price
(December 1988)
¢ CAN/litre



Exchange rate = 1.1960

Structural Changes

Although the major refiners continued to have the largest share of the retail gasoline market, that share declined in most major Canadian centres during 1988. The regional refiners experienced gains at the majors' expense particularly in Saint John, Quebec City and Winnipeg. The largest gains by the independent sector were made in Edmonton.

In September 1988, the federal government advanced the deadline for the elimination of lead in gasoline from December 31, 1992 to December 1, 1990. A marketing strategy implemented by one refiner, as part of its lead phasedown program, was the introduction of a middle grade of unleaded gasoline in selected markets in October 1988.

8.5 Impact of Free Trade Agreement on Canadian Oil Producers

The Canada-U.S. Free Trade Agreement which came into effect January 1, 1989 will eliminate U.S. import tariffs and user fees on both crude oil and petroleum product exports from Canada over a five-year phase out period in equal stages.

The customs user fee, which in 1989 is 0.17% of the border value of crude and products, will decline by one fifth each year beginning January 1, 1990 and be completely phased out on January 1, 1994. With respect to the import tariffs the five-year phase out began on January 1, 1989. Table 8.3 portrays import tariffs for 1988 and 1989 on exports to the U.S.A.

Table 8.5
U.S. Import Duties
¢ US/bbl

Main Product Type	Tariff 1988	Tariff 1989	Tariff Change
Heavy Crude (less than 25° API)	5.25	4.20	1.05
Light Crude (more than 25° API)	10.50	8.40	2.10
Motor gasoline	52.50	42.00	10.50
Distillate	10.50	8.40	2.10
Heavy Fuel Oil	5.25	4.20	1.05

It should be noted that crude producers' revenues on domestic, as well as export sales, will be affected, because Canadian crude oil prices are determined in the U.S. market. The reduction in U.S. import tariffs should theoretically flow through to Canadian producers. Based on crude oil production of 270 000 m^3/d producer revenues could increase by up to Cdn $15 million in 1989.

The relative impact on refined product exports will be somewhat greater, given both the higher level of the tariffs on refined products and the relatively high rates of refinery capacity utilization in the United States.

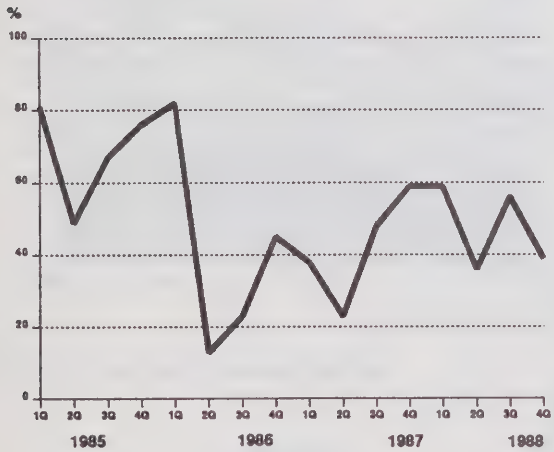
9. Drilling Rig Activity

- *After an upward spike in the third quarter, drilling activity fell off sharply in the fourth quarter.*

- *For 1989 the outlook is pessimistic.*

Drilling rig activity during the fourth quarter of 1988 averaged 223 active rigs compared with 335 rigs a year earlier. This average represents a rig utilization rate of 40%, down almost twenty percentage points from the fourth quarter of 1987. There were 93 fewer active rigs than in the third quarter.

Figure 9.1
Drilling Rig Activity
% Utilization



The fourth-quarter slump in drilling activity, despite the firming of crude oil prices and strong natural gas sales, is attributed to industry cash flow constraints and company budget cuts. As well, seasonal drilling patterns were disrupted as companies accelerated third and early fourth quarter drilling plans to beat expiry dates for several federal and provincial incentive programs, resulting in a spike in activity and a subsequent fall-off.

In response to industry cash flow concerns, the federal government decided to extend Canadian Exploration and Development Incentive Program grants until June 1989. While these grants did not appear to have spurred significant additional drilling in the fourth quarter, they may have prevented an even greater slump. As well the Alberta government extension of two tax breaks, the Alberta Royalty Tax Credit and the three year royalty holiday into 1989, apparently had little short-term impact. The average active rig count during the fourth quarter fell from an October high of 323 rigs to 200 rigs late in December.

On average 268 rigs were active in 1988 compared with 233 in 1987, yielding a rig utilization rate of 48% and 42% respectively. The high point of the year was recorded in early March, just prior to the spring thaw and early indications of a price slump, when 416 rigs were reported active (79% utilization).

Rig activity in 1989 is expected to be much lower than in 1988. The industry consensus is for activity to be about 15% to 20% lower in 1989, assuming oil prices average \$19/bbl (\$120/m^3). It is also expected that more emphasis will be on natural gas exploration. There is continued strong demand for gas in both export and domestic markets and the potential for gas prices to begin edging up, whereas price uncertainty continues to depress oil drilling.

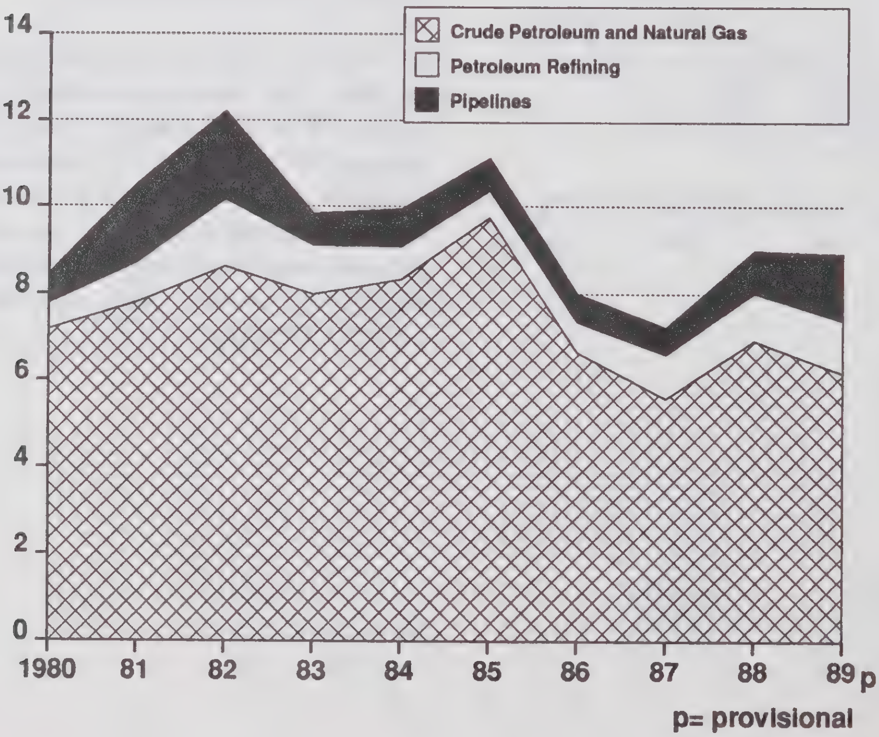
10. Capital Expenditures

- *Although capital expenditures in the upstream oil and natural gas industry are forecast to decline more than 10% in 1989, total energy outlays may increase 9%, because of increases in pipelines, refining and electricity.*

According to a recent (end 1988) survey conducted by Statistics Canada, capital expenditures (including major repairs) in the upstream petroleum and natural gas industry are expected to fall by more than $750 million (11%) in 1989 to $6.2 billion. This level represents a reduction of about 3% from the average expenditures (unadjusted for inflation) over the past three years. As illustrated in figure 10.1, upstream capital expenditures fell off sharply in 1986, recovered marginally in 1988 but appear to have plateaued in the $6 to 7 billion annual range after having peaked in 1985. It should be noted that a larger share of the 1989 expenditures is expected to be directed at the search for and development of natural gas.

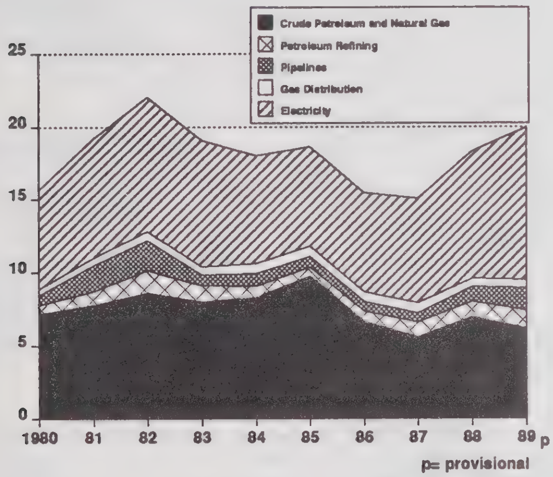
The reduction in upstream capital expenditures is expected to be shared roughly equally by the conventional and non-conventional (synthetic and bitumen) sectors of the industry. Virtually, all of the anticipated reduction in the conventional sector is associated with drilling activity, for both exploration and development. This outcome, when combined with the non-conventional reduction, which had, in recent years, included a lot of drilling for bitumen recovery projects, does not bode particularly well for the upstream service industries, particularly drilling, in 1989.

Figure 10.1
Capital Expenditures
In The Petroleum Industry
$ CAN (Billions)



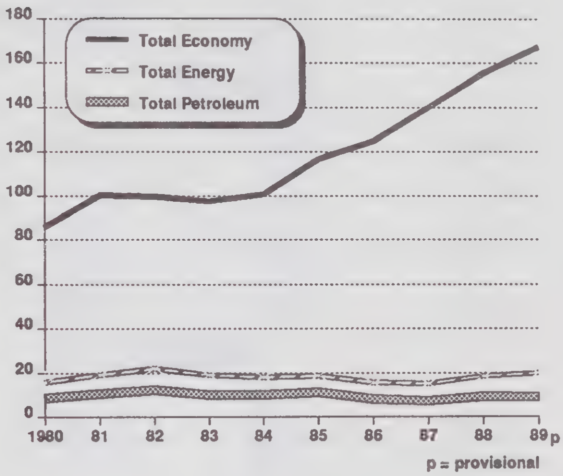
Capital expenditures for both pipelines and petroleum refining are expected to rise significantly, effectively offsetting the fall-off in upstream activity. It should be noted that much of the expected $1.5 billion anticipated for pipelines is related to expansion for the natural gas export market. Expenditures in the petroleum refining sector are also expected to rise sharply (over 12%) to $1.1 billion, as refiners improve their facilities to meet a more demanding mix of product specifications, particularly for transport fuels.

Figure 10.2
Total* Energy Capital Expenditures
$ CAN (Billions)



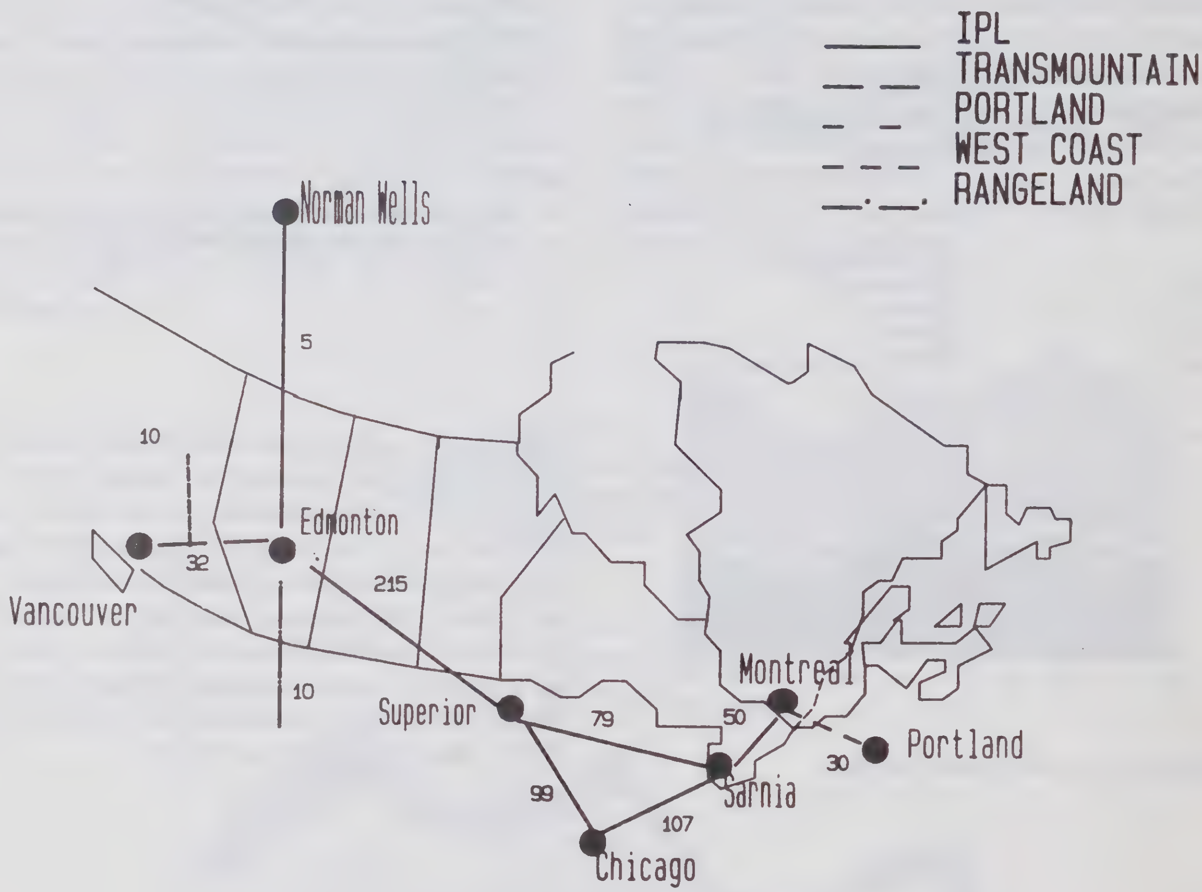
* *excluding coal and uranium mining*

Figure 10.3
Capital and Repair Expenditures
$ CAN (Billions)



While overall capital expenditures in the oil and gas related industries are expected to remain flat in 1989, electricity expenditures should jump sharply, by almost 20%, reaching $10.4 billion, to represent more than half of all energy sector capital expenditures (see figure 10.2). As a result, total energy sector capital expenditures should rise by almost 9% to $20 billion in 1989. With capital expenditures in the entire economy up by about 8%, the energy sector share will rise marginally from 1988 to almost 12% (see figure 10.3).

Appendix I
Major Crude Oil Pipelines in Canada
Location and Capacities



Appendix II
AVAILABLE SUPPLY OF WESTERN CANADIAN
CRUDE OIL AND EQUIVALENT

	1985	1986	1987	1988
PRODUCTION			(000 m^3/d)	
LIGHT/MEDIUM AND EQUIV.				
ALBERTA	138.2	126.1	130.0	134.0
B.C.	5.4	5.5	5.7	5.3
MANITOBA	2.2	2.2	2.1	2.1
SASKATCHEWAN	10.2	11.0	10.7	10.9
OTHER	2.9	3.9	4.2	4.7
	158.9	148.7	152.7	157.0
SYNTHETIC				
SUNCOR	5.8	8.8	6.8	7.8
SYNCRUDE	20.3	20.4	21.7	23.8
	26.1	29.2	28.5	31.6
PENTANES PLUS	10.0	7.8	6.9	6.4
TOTAL LIGHT	**195.0**	**185.7**	**188.1**	**195.0**
HEAVY CRUDE OIL				
ALBERTA CRUDE	26.3	34.0	39.5	43.7
DILUENT (incl. recycled)	4.2	6.7	8.6	9.4
	30.5	40.7	48.1	53.1
SASKATCHEWAN				
CRUDE	21.2	20.7	21.9	22.0
DILUENT	3.0	2.7	3.0	2.9
	24.2	23.4	24.9	24.9
TOTAL HEAVY	**54.7**	**64.1**	**73.0**	**78.0**
TOTAL PRODUCTION	**249.7**	**249.8**	**261.1**	**273.0**
SHUT-IN				
LIGHT	9.8	15.8	6.9	2.1
HEAVY	2.3	4.1	1.3	3.0
	12.1	19.9	8.2	5.1
PRODUCTIVE				
CAPACITY (incl. recy. diluant)	261.8	269.7	269.3	278.1
RECYCLED DILUANT	0.9	0.8	0.9	1.0

SOURCE: National Energy Board

Appendix III
Major Long Term Crude Oil Supply/Demand Assumptions

Non-IPL requirements were derived based on the following assumptions:

- *British Columbia crude oil demand, per NEB long term forecast.*
- *Alberta demand was based on Statistics Canada deliveries for the past five years. About 75% of the incremental forecast volume projected by NEB for the Prairies would go to Alberta.*
- *Approximately 35% of Newgrade feedstock is Fosterton crude which is not considered to be moved via IPL. Over the next five years, that ratio should drop to 20-25% and subsequently fall to 10-15% from 1995 until the end of the forecast period.*
- *Hibernia production is expected to be consumed in Eastern Canada.*
- *2 000 m^3/d of light crude oil will be exported through TMPL.*
- *The TMPL expansion will be completed by early 1990 and then the system will be able to accommodate 6 000 m^3/d of heavy crude oil for the export market.*
- *Approximately 7 000 m^3/d of light crude and 3 000 m^3/d of heavy crude oil is assumed to be exported to Montana refineries.*
- *The IPL sustainable capacity is 190 000 m^3/d at Kerrobert, Saskatchewan. Sustainable pipeline capacity was reduced by approximately 15 000 m^3/d of petroleum products and 10 000 m^3/d of NGL.*

Appendix IVa.

FORECAST SUPPLY, DEMAND AND PIPELINE BALANCES

NEB FORECAST [1] - LOW CASE

000 cubic metre per day

I. LIGHT CRUDE

SUPPLY	1989	1990	1991	1992	1995	2000	2005
Conventional Light	152.2	143.8	135.3	127.6	107.4	82.3	66.5
Synthetic	37.5	39.2	40.5	45.4	50.0	50.1	50.1
Pentanes Plus	3.7	1.0	2.0	2.9	3.9	5.3	3.9
Frontier	0.1	0.1	0.1	0.1	0.1	10.0	13.0
Less Adjustments [2]	-3.0	-2.9	-2.7	-2.6	-2.1	-1.6	-1.3
Total Production	**190.5**	**181.2**	**175.2**	**173.4**	**159.3**	**146.1**	**132.2**
NON IPL DEMAND							
B.C.& NWT	20.1	20.1	20.1	20.1	20.1	20.1	20.1
Alberta	47.5	51.3	50.8	50.2	50.4	51.9	52.9
Atlantic	0.0	0.0	0.0	0.0	0.0	10.0	13.0
RECEIPTS AT CROMER, MAN.	**8.6**	**8.3**	**8.0**	**7.6**	**6.1**	**4.6**	**3.8**
EXPORTS							
TMPL	2.0	2.0	2.0	2.0	2.0	2.0	2.0
Montana	7.0	7.0	7.0	7.0	7.0	7.0	7.0
Total	**85.2**	**88.7**	**87.9**	**86.9**	**85.6**	**95.6**	**98.8**
AVAILABLE FOR IPL	**105.3**	**92.5**	**87.3**	**86.5**	**73.7**	**50.5**	**33.4**

1) *From **Canadian Energy Supply and Demand 1987-2005** released in December 1988.*

2) *Reflects 2% reduction in conventional crude capacity to account for factors such as plant turnaround, operating problems in the field or the effect of weather conditions.*

NEB FORECAST - LOW CASE

000 cubic metre per day

II. HEAVY CRUDE	**1989**	**1990**	**1991**	**1992**	**1995**	**2000**	**2005**
SUPPLY							
Conventional Heavy	35.2	32.6	30.4	24.8	16.7	11.0	6.3
Bitumen	25.2	30.2	30.8	30.3	30.2	31.8	39.4
Diluent	14.2	16.2	15.3	14.0	12.5	12.6	15.3
Less Adjustments	-0.7	-0.7	-0.6	-0.5	-0.3	-0.2	-0.1
Total Production	**73.9**	**78.3**	**75.9**	**68.6**	**59.1**	**55.2**	**60.9**
NON IPL DEMAND							
Alberta	2.8	2.8	2.8	3.1	3.5	3.5	3.8
Saskatchewan	2.2	2.8	2.6	2.4	1.6	1.2	1.0
RECEIPTS AT CROMER, MAN.	6.2	6.0	5.8	5.5	4.4	3.3	2.8
EXPORTS							
TMPL	3.0	5.0	5.0	5.0	5.0	5.0	5.0
Montana	3.6	3.6	3.6	3.6	3.6	3.6	3.6
Total	**17.8**	**20.2**	**19.8**	**19.6**	**18.1**	**16.6**	**16.2**
AVAILABLE FOR IPL	56.1	58.1	56.1	49.0	41.0	38.6	44.7
III. IPL SURPLUS/DEFICIT							
TOTAL CRUDE AVAILABLE FOR IPL	161.4	150.7	143.4	135.6	114.6	89.0	78.0
IPL CAPACITY	165.2	165.2	165.2	165.2	165.2	165.2	165.2
SURPLUS	3.8	14.5	21.8	29.6	50.6	76.2	87.2

Note :

- *Sustainable IPL capacity was measured at Kerrobert, Sask.(190 200) less 15 000 m^3/d of petroleum products and 10 000 m^3/d of NGL deliveries.*

Appendix IVb.
FORECAST SUPPLY, DEMAND AND PIPELINE BALANCES

ERCB FORECAST 1) - HIGH CASE
000 cubic metre per day

I. LIGHT CRUDE

SUPPLY	1989	1990	1991	1992	1995	2000	2005
Conventional Light	162.8	160.9	158.8	154.3	134.3	99.4	78.0
Synthetic	38.5	41.2	41.5	47.5	56.0	84.0	92.0
Pentanes Plus	4.6	3.3	2.2	2.6	-2.8	-2.8	-2.0
Frontier	0.1	2.0	2.0	3.5	15.5	49.0	49.0
Less Adjustments 2)	-3.3	-3.2	-3.2	-3.1	-2.7	-2.0	-1.6
Total Production	**202.7**	**204.2**	**201.3**	**204.8**	**200.3**	**227.6**	**215.4**
NON IPL DEMAND							
B.C.& NWT	20.1	20.1	20.1	20.1	20.1	20.1	20.1
Alberta	50.2	50.4	49.7	49.6	49.0	51.0	52.7
Atlantic	0.0	0.0	0.0	1.5	13.4	25.0	25.0
RECEIPTS AT CROMER, MAN.	8.6	8.3	8.0	7.6	6.1	4.6	3.8
EXPORTS							
Frontier	0.1	2.0	2.0	2.0	2.1	0.0	0.0
TMPL	2.0	2.0	2.0	2.0	2.0	2.0	2.0
Montana	7.0	7.0	7.0	7.0	7.0	7.0	7.0
Total	**88.0**	**89.8**	**88.8**	**89.8**	**99.7**	**109.7**	**110.6**
AVAILABLE FOR IPL	114.7	114.4	112.5	115.0	100.6	117.9	104.8

1) *From **Alberta Oil Supply 1988-2003** released in January, 1989.*

2) *Reflects 2% reduction in conventional crude capacity to account for factors such as plant turnarounds, operating problems in the field or the effect of weather conditions.*

ERCB FORECAST - HIGH CASE

000 cubic metre per day

II. HEAVY CRUDE	1989	1990	1991	1992	1995	2000	2005
SUPPLY							
Conventional Heavy	44.1	45.5	46.4	42.3	35.8	23.0	14.0
Bitumen	26.0	32.0	35.0	41.0	59.0	63.0	60.0
Diluent	14.4	16.7	17.8	19.4	24.8	24.8	23.0
Less Adjustments	-0.9	-0.9	-0.9	-0.8	-0.7	-0.5	-0.3
Total Production	83.6	93.3	98.3	101.9	118.9	110.3	96.7
NON IPL DEMAND							
Alberta	2.8	2.8	3.0	3.1	3.7	4.4	4.4
Saskatchewan	2.2	2.8	2.6	2.4	1.6	1.2	1.0
RECEIPTS AT CROMER, MAN.	6.2	6.0	5.8	5.5	4.4	3.3	2.8
EXPORTS							
TMPL	3.0	5.0	5.0	5.0	5.0	5.0	5.0
Montana	3.6	3.6	3.6	3.6	3.6	3.6	3.6
Total	17.8	20.2	20.0	19.6	18.3	17.5	16.8
AVAILABLE FOR IPL	65.8	73.1	78.3	82.3	100.6	92.8	79.9
III. IPL SURPLUS/DEFICIT							
TOTAL CRUDE AVAILABLE FOR IPL	180.6	187.5	190.8	197.3	201.2	210.8	184.8
IPL CAPACITY	165.2	165.2	165.2	165.2	165.2	165.2	165.2
DEFICIT	- 15.4	-22.3	-25.6	-32.1	-36.0	-45.6	-19.6

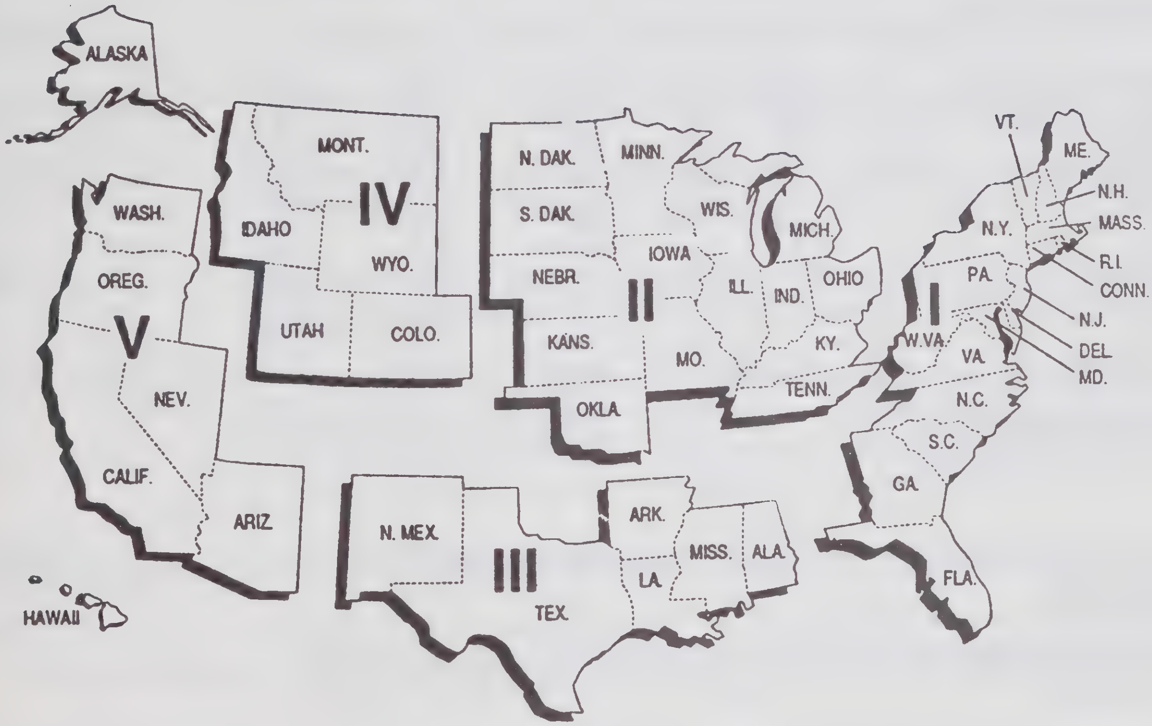
Note :

- *Sustainable capacity was measured at Kerrobert, Saskatchewan (190 200 m^3/d) less 15 000 m^3/d of petroleum products and 10 000 m^3/d of NGL deliveries.*

- *Total ERCB supply forecast was derived by adding supply outside Alberta (as per NEB) to ERCB Alberta supply.*

- *Non IPL demand was mainly taken from NEB 1988 long term forecast.*

Appendix V
U.S. Petroleum Administration for Defense (PAD) District



Appendix VI
Consumption Taxes on Petroleum Products
(December 1, 1988)

	Ad valorem				Gasoline	
	Mogas	Diesel (%)	Reg L	Reg UL	Prem UL (cents per litre)	Diesel
FEDERAL TAXES						
Sales			3.40*	3.40*	3.48*	2.60*
Excise			6.5	6.5	6.5	4.0
PROVINCIAL TAXES						
Newfoundland (a)	22	26	9.3*	9.3*	9.3 *	11.5
Prince Edward Island	20	23	8.3*	8.3 *	8.3*	8.8
Nova Scotia	20	21	8.2*	8.2*	8.2*	8.5*
New Brunswick	20	23	7.9*	8.3*	8.8 *	8.4*
Quebec (b)			14.4	14.4	14.4	12.45
Ontario			12.3	9.3	9.3	9.9
Manitoba			9.8	8.0	8.0	9.9
Saskatchewan			7.0	7.0	7.0	7.0
Alberta			5.0	5.0	5.0	5.0
British Columbia (c)	22.5(d)		8.96*	6.96*	6.96*	7.40*
Yukon			4.2	4.2	4.2	5.2
Northwest Territories (e)			8.4	8.4	8.4	7.1

(a) The gasoline tax is reduced by 1.5 cents per litre in the region between the Quebec border and Red Bay in Labrador.

(b) Reduced by varying amounts in certain remote areas and within 20 kilometers of the provincial and U.S. borders.

(c) Additional transit tax of 3.0 cents per litre in Vancouver.

(d) This applies to unleaded gasoline. Taxes on leaded gasoline and diesel fuel 2.0 and 0.44 cents per litre higher, respectively, than the unleaded tax.

(e) 85% of gasoline tax.

** Changed since last quarter.*

Glossary

Bitumen	A naturally occurring viscous mixture composed mainly of hydrocarbons heavier than pentane, which may contain sulphur compounds and which in its natural state is not recoverable at a commercial rate through a well.
Conventional areas	Those areas of Canada that have a long history of hydrocarbon production. Conventional areas are also referred to as nonfrontier areas.
Crude oil and equivalent	Includes crude oil, synthetic crude, oil produced from oil sands plants, and condensate.
Feedstock	Raw material supplied to a refinery or petrochemical plant.
Heavy crude oil	Loosely applied, crude oils with a low API gravity (high density).
In situ recovery	With reference to oil sands deposits, the use of techniques to recover bitumen without the necessity of mining the sands.
Light crude oil	Crude oil with a high API gravity (low density). Generally includes all crude oil and equivalent hydrocarbons not included under heavy crude oil.
Natural gas liquids	Those hydrocarbon components recovered from raw natural gas as liquids by processing through extraction plants, or recovered from field separations, scrubbers or other gathering facilities. Includes the hydrocarbon components ethane, propane, butane and pentanes plus, or a combination thereof.
Oil sands	Deposits of sands and other rock aggregate that contain bitumen.
Pentanes plus	Also referred to as condensate. A volatile bydrocarbon liquid composed primarily of pentanes and heavier hydrocarbons. Generally a by-product obtained from the production and processing of natural gas.
Productive capacity	The estimated production level that could be achieved, unrestricted by demand, but restricted by reservoir performance, well density and well capacity, oil sands mining capacity, field processing and pipeline capacity.
Shut-in capacity	The unused production capability of currently producing oil and gas wells plus the total production capability of all shut-in oil and gas wells, whether or not they are connected to surface gathering and production facilities.
Synthetic crude oil	Crude oil produced through treatment of oil sands in upgrading facilities designed to reduce the viscosity and sulphur content.

The Canadian Oil Market

Vol. V, No. 1, First Quarter 1989

Energy, Mines and Resources Canada
Énergie, Mines et Ressources Canada

Canada

THE ENERGY OF OUR RESOURCES

THE POWER OF OUR IDEAS

THE CANADIAN OIL MARKET

Vol. V, No. 1, First Quarter 1989

Canadian Oil Markets and Trade Division
Energy Sector
Energy, Mines and Resources Canada

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Table of Contents

List of Figures

Appendices

List of Tables

Appendices

The Canadian Oil Market

Overview

- *In line with a robust economy, seasonally-adjusted oil consumption in Canada remained strong in the first quarter, marking the third consecutive quarter of growth. Demand for transportation fuels was particularly strong.*

- *After two years of very little change the decline curve for conventional light crude productive capacity has reappeared. Bitumen supply has also slipped for the second quarter in a row.*

- *Demand for domestic crude by Canadian refiners shifted towards heavy crude with the start-up of the Newgrade upgrader, thus freeing up light crude. Total crude exports declined, although light crude exports were up slightly as U.S. demand continued strong.*

- *By the end of March 1989, crude prices were up about 20% reflecting apparent OPEC cohesion and a series of accidents in the international oil market.*

- *The industry remains skeptical about the durability of higher prices however. Exploration activity, which is usually at its peak during the winter, declined by a third in the first quarter.*

- *The Canadian trade surplus in most energy commodities declined in the first quarter, in part as a result of reductions in the exportable surplus and transportation constraints.*

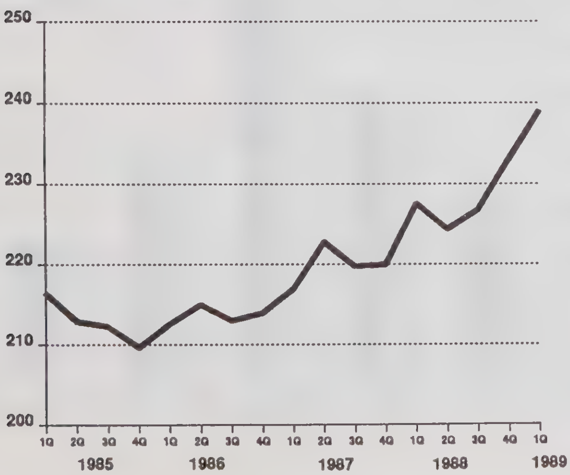
1. Domestic Demand

- *In the first quarter, domestic petroleum product sales continued strong for the third consecutive quarter.*
- *Growth was spread throughout the country, except in the Prairies where sales declined slightly.*

1.1 Seasonally-Adjusted

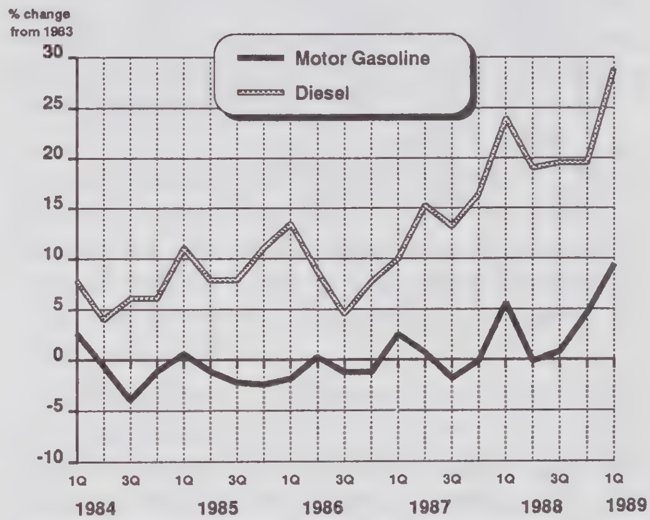
Seasonally-adjusted petroleum product consumption in Canada during the first quarter of 1989 averaged 239 000 m^3/d, up 5% from the 1988 average. This marked the third consecutive quarter of uninterrupted growth in seasonally-adjusted product sales. The strong, sustained increase in consumption was largely the product of continuing economic growth in the first quarter of 1989, in conjunction with relatively low crude oil prices in the summer and fall of 1988 which subsequently reached their full impact on product prices in the fall and winter, after a lag resulting from the time taken to deliver the crude oil to the refineries, and to refine and market the products. Thus, with Gross Domestic Product over 4% higher, and refined product prices averaging from 5 to 7% lower in real terms than during the same period last year a substantial year-over-year increase in product sales was to be expected.

Figure 1.1.1
Total Petroleum Product Consumption
(Seasonally Adjusted)
000 m^3/d



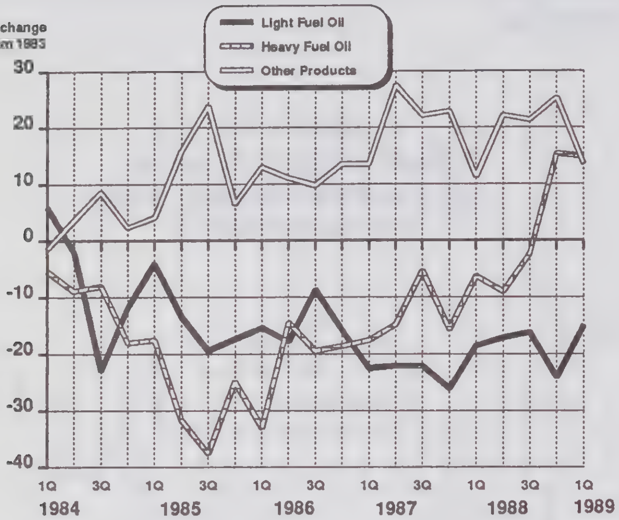
Relative to 1988 annual averages, consumption was up in the first quarter in all the "main" product categories although sales in the miscellaneous category "other products" did record a decline of 5%. Motor gasoline sales rose by 6% to approach 100 000 m^3/d and accounted for 42% of total product consumption. Diesel fuel demand, with a 20% market share, was up 7% to 49 000 m^3/d.

Figure 1.1.2
Trends in Motor Gasoline and Diesel Fuel Consumption
(Seasonally Adjusted)



Sales of heating oil, which accounted for 10% of product demand, increased by 5% to approach 22 000 m^3/d, reflecting the fact that during the heating season this year, temperatures were about 4% colder, on a degree-day basis, in central and eastern Canada where almost 90% of all heating oil in Canada is consumed.

Figure 1.1.3
Trends in Non-Transportation Fuel Consumption
(Seasonally Adjusted)



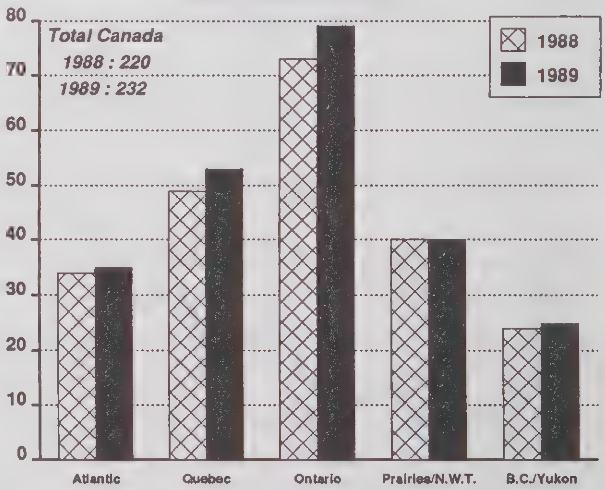
Heavy fuel oil consumption, which comprised 11% of product sales, continued to show the largest gains on a percentage basis with sales up 15% to over 25 000 m^3/d in the first quarter. The strong demand for heavy fuel oil reflects its increased use in thermal electricity generation, most notably in the Atlantic and Ontario regions; high activity in the pulp and paper industry; and interfuel substitution towards heavy fuel oil, stemming from its comparatively low price vis-à-vis other energy sources in Ontario and Quebec. Since 1985, when heavy fuel oil sales bottomed out, the recovery has been quite strong, so that by 1989, sales were roughly 15% higher than 1983. The 5% decline in "other products" consumption to 44 000 m^3/d appears to reflect some "levelling off" in demand which began last year. Prior to then "other products" sales had risen rather steadily since the economic recovery that started in 1983.

1.2 Regional Consumption

About 232 000 m^3/d of refined products were consumed in the first quarter (before adjustment for seasonality). Consumption in the Atlantic region grew by 3% to account for 15% of total product sales. Growth in the Atlantic sales was fairly evenly spread across all products, ranging from a 6% increase in heavy fuel oil sales to virtually no change in sales in the case of diesel fuel and heating oil.

Growth in product consumption was significantly stronger in Quebec. Sales in this region were up over 7% relative to last year and represented 23% of the Canadian total. However, about three-quarters of the increase was attributable to the dramatic surge in heavy fuel oil demand which rose by 65%. The increase in heavy fuel oil sales largely reflected its strong demand by the Quebec pulp and paper industry and the expiration of price incentives by Quebec Hydro in mid-1988 which induced some sectors of industry to switch back from electricity to heavy fuel oil. With the exception of "other products" which actually recorded a 12% decline in sales from last year, the remaining product categories recorded more modest gains.

Figure 1.2.1
Regional Petroleum Product Consumption
(First Quarter)
000 m^3/d



With an increase of 7.5%, Ontario recorded the highest growth in product consumption among all the regions and accounted for over a third of total product sales. Heavy fuel oil sales were almost 40% higher than they were last year, largely because of the reactivation of some oil-fired electric power generation units to meet peak load demand requirements. Motor gasoline and "other products" sales were up 6% and 10%, respectively, reflecting the healthy state of the region's economy.

The Prairies (and Territories) was the only region to show no growth in overall product consumption from last year. Although heavy fuel oil sales were up 38%, this increase was on relatively small volumes and was completely offset by the decline in sales of "other products" and heating oil. Moreover, motor gasoline and diesel fuel consumption rose only marginally. Prairie demand, which accounted for 17% of total product sales, continued to be adversely affected by the economic after-effects of the drought and low oil prices in 1988.

Refined product sales in British Columbia, which accounted for 11% of the Canadian total, were almost 7% higher than first quarter 1988 levels. Increases in sales were recorded across all product categories with heating oil showing the largest gains at almost 30%. The substantial increase in heating oil demand likely reflects some inventory build by distributors and consumers and the fact that temperatures in the region during the first quarter were almost 15% colder than they were at the same time last year. Heavy fuel oil consumption was also up substantially, at 14%. As in Quebec, this largely reflected higher activity in the pulp and paper industry. Sales in the remaining product categories showed more modest gains. In order to meet higher demand requirements, B.C. refiners "imported" more refined products from Alberta, as well as increased refinery throughput.

1.3 International Oil Consumption

As shown in table 1.3 the year-over-year growth in product sales in Canada during the first quarter was substantially higher than any of the three major industrialized regions which collectively account for about 60% of total refined product consumption in the non-communist world. The strong growth in Canadian oil demand was to be expected, as Canadian economic growth also exceeded many of the other industrialized regions. Sales in the United States were virtually at the same level as they were in the first quarter of 1988 with a decline in middle distillate consumption completely offsetting the marginal increases in the consumption of the other products.

Taken together, the countries in Europe also recorded little change in overall product sales. However, this conceals the fact that consumption growth was relatively high in Italy and France, up 8.4% and 4.7%, respectively, whereas it only increased marginally in the United Kingdom and fell dramatically, by 11%, in West Germany where consumers had built inventories late in 1988 in anticipation of a 1989 tax increase on fuel. European sales of heavy fuel oil rose significantly reflecting problems with nuclear power plants and drought; middle distillate demand, on the other hand, declined, largely because of exceptionally mild weather which lowered heating oil sales.

Product consumption in Japan continued to rise in the first quarter of 1989, albeit at a slower pace than that recorded for 1988 as a whole. Sales in all the main product categories nevertheless grew substantially, reflecting Japan's continuing economic expansion and rising income level.

Table 1.3
Petroleum Product Consumption
% Change 1988/1989*
(First Quarter)

Product	Canada	U.S.A.	OECD Europe**	Japan
Motor Gasoline	3.7	0.6	3.0	4.7
Middle Distillate	3.9	-4.8	-8.0	7.1
Heavy Fuel Oil	22.5	0.7	9.3	4.3
Other Products	1.5	2.9	5.6	0.6
Total	**5.2**	**-0.2**	**0.1**	**3.1**

* *Preliminary*
** *Includes West Germany, Italy, France and the United Kingdom*

2. Refinery Utilization and Stocks

- *Along with product consumption, refinery capacity utilization rates continued strong.*

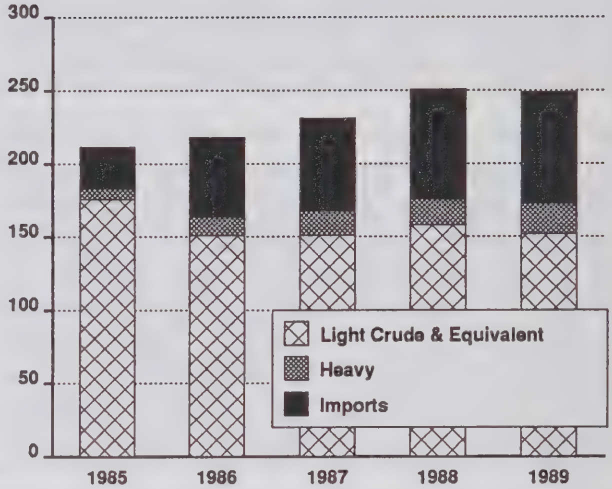
- *In some regions increased product imports and a stock drawdown were also necessary to meet domestic product sales.*

2.1 Refinery Utilization

There was very little change in total refinery receipts of crude oil and equivalent (excluding partially processed oil) in the first quarter of this year compared with 1988. They remained at the relatively high level of almost 250 000 m^3/d. Imports were virtually the same, at 76 000 m^3/d, while domestic receipts fell marginally, to 174 000 m^3/d. The mix of domestic light and heavy crude at Canadian refineries shifted however, with heavy crude receipts increasing more than 15%. Light crude and equivalent deliveries fell 5 000 m^3/d, to 152 000 m^3/d. Conventional light crude receipts declined 10 000 m^3/d, to 115 000 m^3/d, as a result of a 25% drop in Quebec deliveries and lower receipts in western Canada. An increase in synthetic crude use offset about half the decline in conventional crude.

With the start-up of its Newgrade upgrader in late 1988, Consumers' Co-op refinery in Saskatchewan has reduced considerably its demand for light crude while increasing its demand for heavy crude. Moreover, heavy crude is a suitable feedstock for the production of heavy fuel oil which has been in high demand recently, particularly in eastern Canada. Finally, domestic light crude oil is becoming increasingly less available given the natural decline in the productive capacity of conventional oil wells.

Figure 2.1
Crude Oil and Equivalent Receipts
At Canadian Refineries
(First Quarter)
000 m^3/d



Crude oil and equivalent run to stills was about 11 000 m^3/d higher than crude oil receipts in the first quarter. To meet the increased throughput requirements refiners drew down crude inventories and ran more partially processed oil (in total 9 000 m^3/d) through the refining system.

On a year-over-year basis there was a jump of nearly 5% in the average refinery utilization rate, bringing it to 87%, and to the highest first quarter level of the decade. Even in the Atlantic region the utilization rate stood above 80%.

Excluding partially processed oil, throughput rose by about 6 000 m^3/d (2%). In order to meet increased refined product demand, which was up by nearly 12 000 m^3/d, refiners and marketers drew down product stocks and imported more finished products, while exporting less.

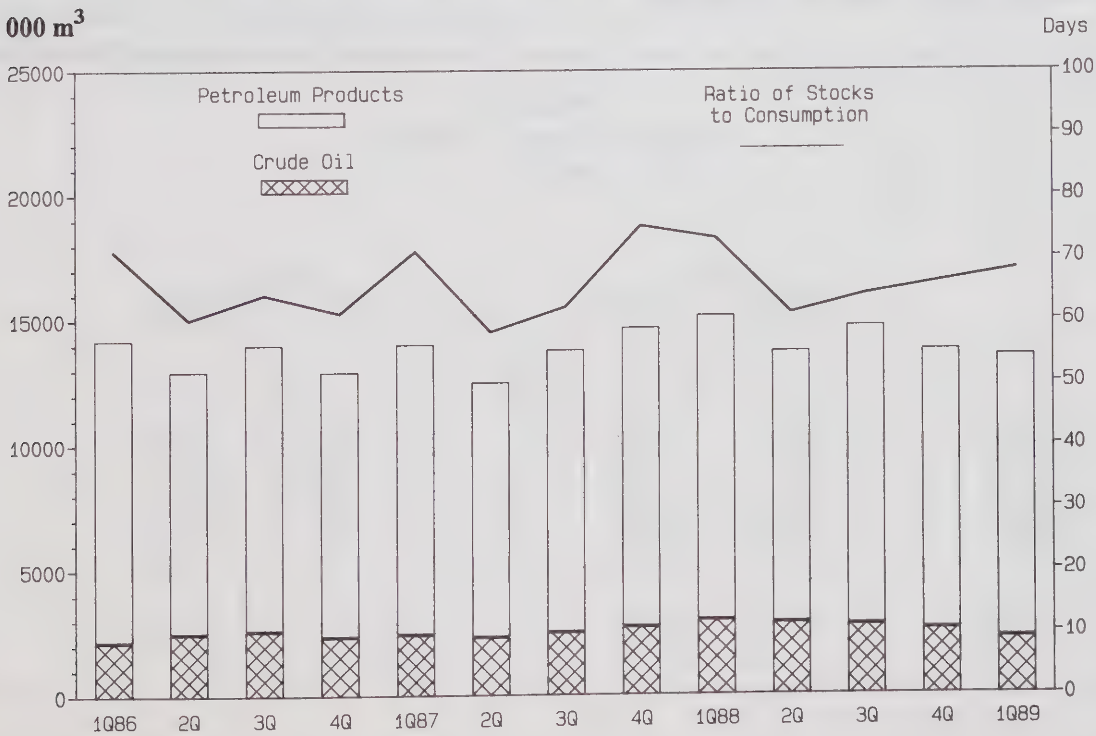
Table 2.1 Refinery Utilization (First Quarter)	1987	1988	1989
		(%)	
Atlantic	74	78	83
Quebec	91	91	93
Ontario	86	84	90
Prairies	77	85	83
B.C.	88	84	88
Canada	**83**	**84**	**87**

As shown in table 2.1 the greatest improvement in refinery utilization has been in the Atlantic region and Ontario, as a result of the strong consumption growth in eastern Canada. In Quebec however, much of the higher product demand was met through increased product imports.

In the Prairies the decline in throughput matched the fall off in consumption. Although total throughput increased in British Columbia, the use of crude oil as feedstock fell, commensurate with a doubling in the use of partially processed oil as refinery input. Partially processed oil accounted for 25%, or 6 000 m^3/d, of total throughput in the first quarter of 1989, compared with 12% in the first quarter of 1988. Most of the partially processed oil originates from Edmonton refineries. In order to increase the efficiency of refinery operations, the refining and marketing sectors in Vancouver and Edmonton are developing closer economic links.

2.2 Stocks

Figure 2.2
Closing Crude and Product Inventories in Canada



Crude and petroleum product closing stocks in March were 13.6 million cubic metres, down 11% from the year before, reflecting a substantial inventory draw of about 30 000 m^3/d during March. Drawdowns in both crude and product stocks were required to satisfy strong domestic product demand in the face of relatively steady refinery crude oil receipts, but higher throughput requirements. Crude stocks declined 25%, to 2.2 million cubic metres, relative to last year while the much larger product inventories were 7% lower at 11.3 million cubic metres. In fact, because of the large March drawdown, both crude and product stocks were also below the levels of March 1986 and March 1987.

The decline in product stocks was spread across all the major products. Motor gasoline and diesel stocks were down 5% and 13% respectively, while light and heavy fuel oil inventories recorded declines of 19% and 5%. "Other products" stocks remained virtually unchanged from last year.

For the second consecutive quarter, total inventories dropped below the previous year's level as a result of a significant drawdown in the last month of the quarter. In addition, during the first quarter of 1989 there was a slight inventory draw rather than the traditional build, which usually occurs prior to the refinery maintenance period of the second quarter. As a result, given generally strong demand, absolute inventories are at a relatively low level entering the second quarter of the year.

As shown in table 2.2.1, compared with March 1988, petroleum product stocks increased moderately in the Atlantic while declining in all other regions -most significantly in the Prairies where they were down 20%. On the other hand, it was the Atlantic region, with a decline of more than 50% in crude stocks, which accounted for most of the drop in crude oil stocks.

As demonstrated in section 2.1 refiners can react to increases in crude oil or petroleum product demand in a variety of ways, including increasing crude run to stills, drawing down stocks, importing more products and exporting less. During the first quarter of 1989 refiners in the Atlantic drew down crude stocks and increased refinery throughput to meet incremental demand. In Quebec refiners also drew down crude stocks; however, in addition they imported more products rather than drawing down product stocks.

In contrast, crude and product inventories changes in Ontario were marginal, as refiners increased crude receipts and refinery throughput to satisfy strong consumer demand. Refiners in British Columbia combined greater utilization of semi-refined oil (mainly from Alberta) with increased deliveries of refined products from Alberta to meet the 6% jump in consumption.

Table 2.2.1
Closing Inventories by Region
March

	1988		1989	
	Crude	**Product**	**Crude**	**Product**
	($000\ m^3$)			
Atlantic	1370	1870	600	1940
Quebec	620	2290	780	2220
Ontario	610	3740	550	3460
Prairies	230	3190	220	2560
B.C.	100	1120	70	1160
Canada	**2930**	**12210**	**2220**	**11340**

Table 2.2.2
Ratio of Stocks to Consumption
End March

	Crude			Products		
	1987	1988	1989	1987	1988	1989
	Days					
Atlantic	30	52	26	71	71	84
Quebec	23	5	18	58	57	52
Ontario	7	8	8	50	52	50
Prairies	6	5	5	75	73	61
B.C.	4	5	3	51	47	52
Canada	**12**	**14**	**11**	**59**	**59**	**57**
Canada (excl. Atlantic)	**10**	**9**	**9**	**53**	**61**	**53**

At the national level, the ratio of stocks to consumption, as of the end of the first quarter 1989, was 7% below the 1988 level, reflecting lower crude and product stocks in the Atlantic and the Prairies respectively, and strong consumption growth. Excluding the Atlantic region, which has wider crude stock fluctuations, the national stocks to consumption ratio remained unchanged, at 9 days. On the product side however, it slipped 8 days to 53 days. In addition to the domestic market, the level of demand in the product market in the United States also has a strong influence on the level of Atlantic product stocks.

Including approximately 8 days of crude stocks held in tankage along crude oil pipelines, total national days of supply stood at 71, 4 days higher than the average of the Organization for Economic Cooperation and Development (OECD) countries. Including public stocks, however, the OECD number rises to 95 days.

3. Crude Oil Supply and Disposition

- *After two years of very little change, the decline curve for conventional light crude has reappeared.*
- *Light crude capacity in Alberta fell 4% in the first quarter.*
- *For the second consecutive quarter bitumen supply also slipped, reflecting crude oil price uncertainties.*

3.1 Light Crude Oil Supply and Disposition

Productive capacity of Alberta conventional light crude oil averaged 134 000 m^3/d during the first quarter of 1989, down almost 4% (5 000 m^3/d) from the same period last year. This reduction reflects a return to the "natural decline" of existing conventional light crude wells after a upward spike in 1987 and 1988 coincidental with the addition of pipeline capacity. Other factors such as lower crude oil prices experienced during the second half of 1988, the reduction of government drilling incentives and unusually cold weather in January and February also contributed to this decline. Since the first quarter of 1985, Alberta supply has declined about 17 000 m^3/d, or 11%. Productive capacity of the other producing regions remained unchanged from last year, at 23 000 m^3/d.

Synthetic crude oil production averaged 29 000 m^3/d in the first quarter, up 11% from a year ago. All of the improvement is attributable to increased throughput at the Suncor plant. Because of the October 1987 fire, production was only 5 000 m^3/d in the first quarter of 1988, compared with 8 000 m^3/d this year. Although the Capacity Addition Program at Syncrude was completed in the fall of 1988, increasing the plant capacity about 3 000 m^3/d, to 28 000 m^3/d, Syncrude production remained unchanged at 21 000 m^3/d, mainly because of maintenance programs in both 1988 and 1989. Synthetic crude production accounted for 14% of total Canadian light crude oil and equivalent production, up one percentage point from last year.

Including pentanes plus production of 18 600 m^3/d, total available supply of Canadian light crude and equivalent was at 205 000 m^3/d, down slightly from a year ago, with the higher synthetic output only partially offsetting the decline in conventional capacity.

As in 1988, light crude shut-in productive capacity remained marginal, at about 3 000 m^3/d, primarily as a result of tight pipeline capacity. Production of conventional oil in Alberta declined by 5 000 m^3/d to 132 000 m^3/d; however, most of the drop was offset by higher synthetic output.

Figure 3.1.1
Conventional Light and Medium Crude Oil Productive Capacity
(First Quarter)
000 m^3/d

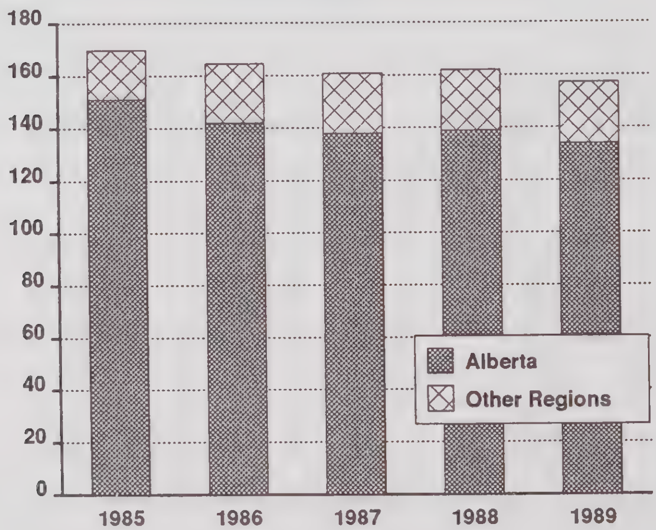
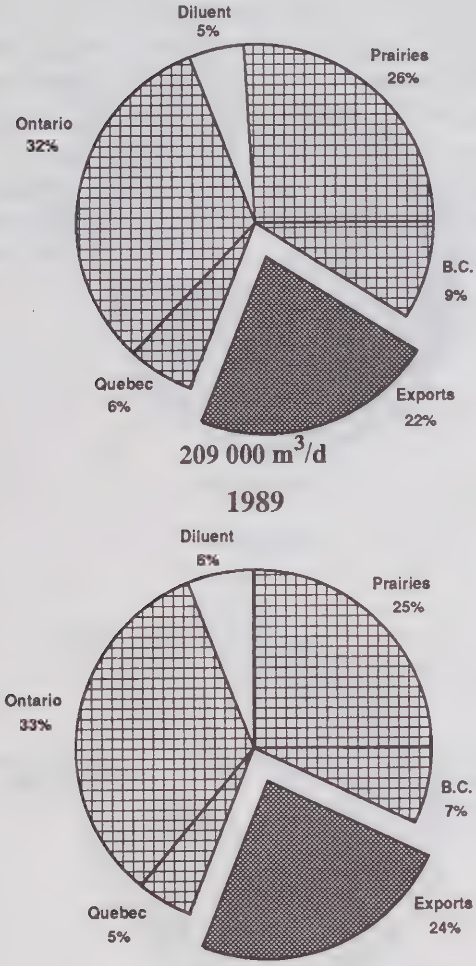


Figure 3.1.2
Light Crude Oil and Equivalent Disposition*
(First Quarter)

1988



207 000 m^3/d

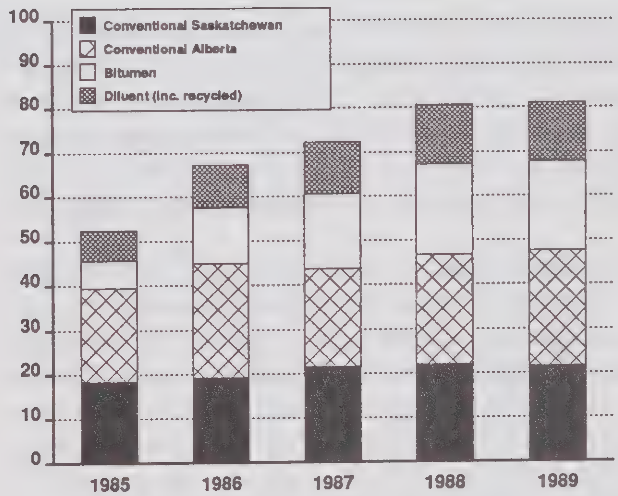
* *Includes inventory draw of 4 000 m^3/d in 1988 and 2 000 m^3/d in 1989.*

As a result of a reduction in conventional crude oil requirements at the Consumers Co-op refinery in Regina, Saskatchewan, increased deliveries of partially processed oil from Edmonton to Vancouver, and a drop in deliveries to Quebec, refinery demand for Canadian light crude oil fell 5 000 m^3/d (3.3%) to 145 000 m^3/d from a year ago. Ontario was the only region to record an increase, up 8% to over 68 000 m^3/d. Demand by U.S. refiners remained strong. In addition, foreign demand was stimulated by the fact that Canadian crude prices lagged slightly behind the general world-wide increase in prices which occurred throughout the quarter. Therefore, despite a slight decline in total light crude production, exports were about 5% higher.
(See Appendix II for more details.)

3.2 Heavy Crude Oil Supply and Disposition

Despite a decline in bitumen supply, overall "neat" heavy crude oil productive capacity during the first quarter of 1989 increased marginally, to 68 000 m^3/d, as compared to last year.

Figure 3.2.1
Heavy Crude Oil Productive Capacity
(First Quarter)
000 m^3/d



Unblended conventional heavy crude oil productive capacity averaged 48 000 m^3/d, up 3% from last year. Virtually all of the increase was recorded in Alberta (total capacity, 26 000 m^3/d) reflecting increased drilling in the province particularly in the Bow River area. Part of the increase may have resulted from higher drilling activity last summer when producers took advantage of government drilling incentives before their reduction in September 1988.

It is difficult to assess the long-run impact of short-term drilling incentives on the level of crude oil supply. The supply benefits may be short term only and reflect increased in-fill drilling more than anything else. For example, while conventional heavy crude oil capacity is up on a year-over-year basis, it has fallen below the level of the third and fourth quarters of 1988, when drilling activity was greater (see Section 8).

Low oil prices experienced during the second half of 1988 had the effect of slowing down or postponing the development of several bitumen projects. For the second consecutive quarter bitumen production fell - by 2% to slightly more than 20 000 m^3/d. If crude prices recover and remain higher (crude oil prices rose about $US 3/bbl during the first quarter of 1989) most of these projects could be brought back on stream relatively quickly. Under the current circumstances however, bitumen capacity is not expected to return to 1988 levels until the fourth quarter of 1989. The industry has adopted a wait and see attitude with respect to the crude oil price increase.

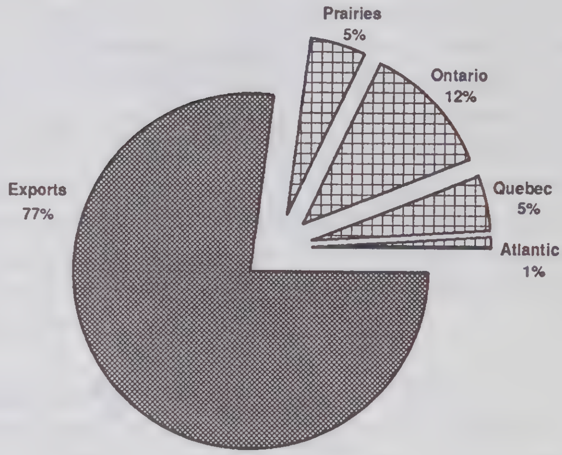
Pentanes plus requirements (including recycled) for blending purposes averaged 13 000 m^3/d, basically unchanged from last year. Total blended heavy crude oil production averaged 79 000 m^3/d (including recycled diluent), barely up over the same period last year. The shut-in level, averaging 2 500 m^3/d, was also unchanged.

Canadian demand for heavy crude rose more than 15% to 23 000 m^3/d. About half of the increase was recorded in the Prairies reflecting the start-up of the Newgrade upgrader. Both Quebec and Ontario recorded an increase of 1 000 m^3/d, to 5 000 m^3/d and 10 000 m^3/d, respectively, in part reflecting the substantial increase in heavy fuel oil consumption in these regions (see Section 1.1.) In British Columbia approximately 1 000 m^3/d of heavy crude oil was delivered as refiners experimented with heavy crude as a feedstock.

With increased domestic demand, flat production and no apparent major stock draw, exports fell more than 7 000 m^3/d to 58 000 m^3/d.

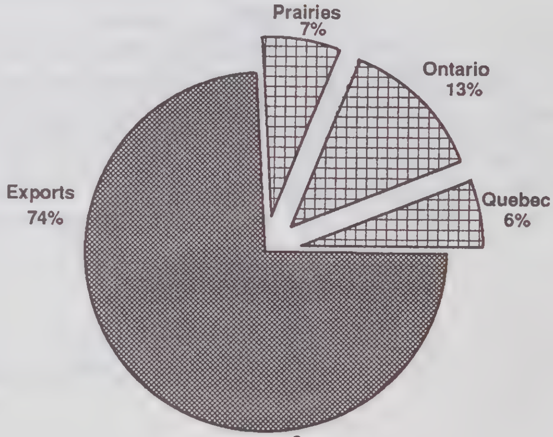
Figure 3.2.2
Heavy Crude Oil Disposition
(First Quarter)

1988



83 000 m^3/d *

1989



79 000 m^3/d

** Includes inventory draw of about 5 000 m^3/d.*

Since the Newgrade upgrader became operational in December 1988 it has had its share of difficulties. Unanticipated problems with the coker unit, largely stemming from the nature of the feedstock, have resulted in frequent coker turnarounds at the plant. Mainly as a result of the coker problems, Newgrade has generally been operating at only about 60% of capacity. On April 1, 1989 the upgrader was shut down to perform routine maintenance, and to repair its hydrogen unit which was damaged in a March fire at the plant.

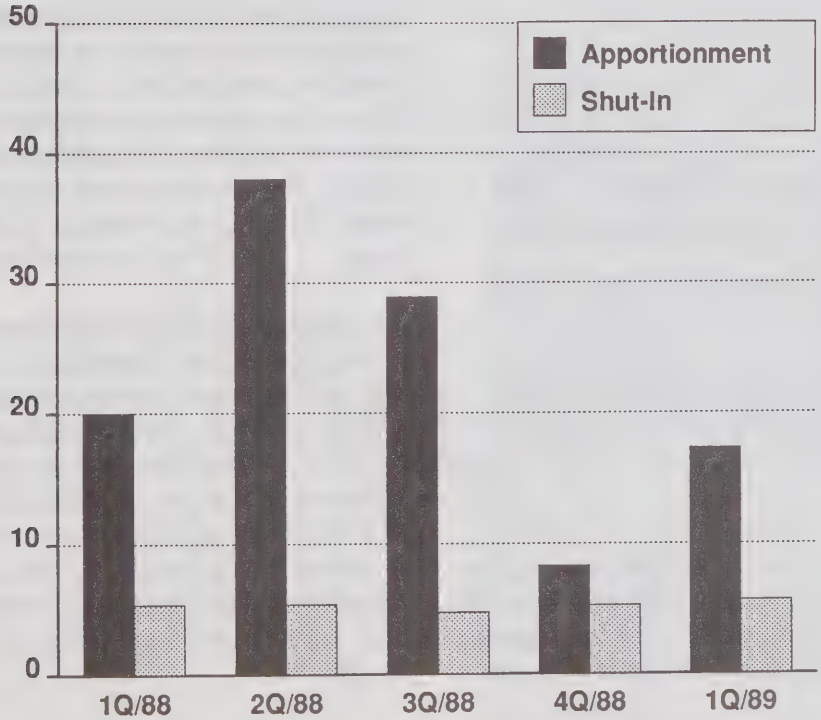
3.3 Pipeline Apportionment

Apportionment on the Interprovincial Pipe Line (IPL) during the first quarter of 1989 averaged 17 000 m^3/d (or 9%), down 13 000 m^3/d from the same period last year. Working together, the industry and the Alberta goverment have tackled the problem of overnominations by shippers and improved the crude nominations process. Crude oil supply however, exceeded pipeline capacity in every month. In February, a reduction of 3 000 m^3/d in pipeline capacity because of maintenance work was also a factor.

Mainly as a result of IPL apportionment, Trans Mountain and Rangeland pipelines also operated at close to capacity throughout the quarter. In March, Trans Mountain had a apportionment of 8% or 3 000 m^3/d, reflecting incremental shipments of heavy crude oil and the shipment of light crude feedstock to Washington state refineries (see Section 4.1). In January, however, Trans Mountain had spare capacity of 2 000 m^3/d. On the Rangeland system, spare capacity averaged 1 000 m^3/d.

Approximately half of the 5 000 m^3/d plus of shut-in during the first quarter could be attributable to the lack of transportation capacity. The balance was the result of low crude prices.

Figure 3.3
IPL Apportionment and Crude Oil Shut-In
000 m^3/d



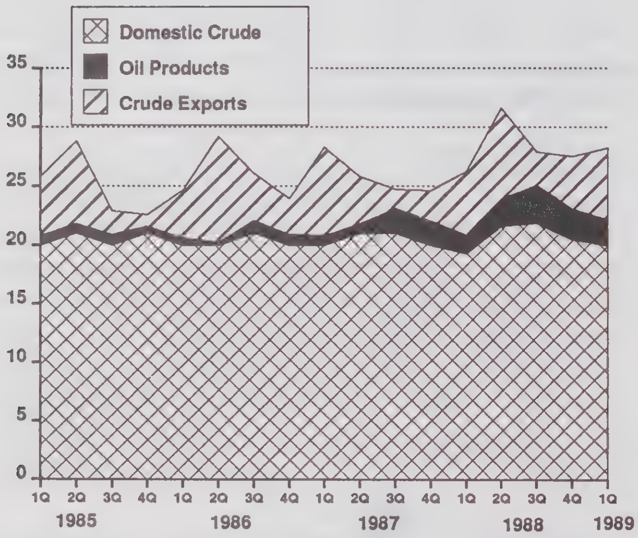
4. Pipeline Utilization

- *Despite strong demand, total throughput on Canadian pipelines was down slightly in the first quarter, primarily because of weather, and technical constraints on the IPL system.*

4.1 Trans Mountain Pipe Line Throughput

Trans Mountain Pipe Line (TMPL) throughput averaged a little over 28 000 m^3/d during the first quarter of 1989, up 8% from the same period a year ago, although virtually unchanged from the average throughput for 1988 as a whole. TMPL operated at close to capacity throughout most of the quarter and indeed there was a need for an 8% apportionment in March.

Figure 4.1
TMPL Deliveries
000 m^3/d



First quarter deliveries to Vancouver-area refineries increased to 20 000 m^3/d, or by about 4% relative to the first quarter of 1988 despite a 16% decline in light crude deliveries to 13 000 m^3/d. This decline however, was more than offset by the increasingly large volumes of semi-refined oils being shipped from Edmonton refineries for final processing in Vancouver. These deliveries, averaging about 6 000 m^3/d, were almost double those of last year.

About 2 200 m^3/d of refined products or 8% of total deliveries were moved from Edmonton to TMPL's terminal in Kamloops. This was about 30% higher than volumes delivered last year. Pipeline exports, largely of condensate, to the Anacortes-Ferndale refining area in Washington state averaged about 2 800 m^3/d or 10% of total shipments. This was a significant increase over the corresponding period in 1988 when less than 600 m^3/d was delivered to this area and in fact it was the incremental shipments of condensate which in large part led to the need for apportionment in March. Washington state refiners tripled their imports of Canadian condensate from last year as their more traditional source of supply from Indonesia was temporarily diverted to the Asian Pacific market.

Overall light crude shipments, including exports, were 17 000 m^3/d, down about 5% from the same period last year. Heavy crude deliveries were also marginally lower. Although Vancouver refineries increased their heavy crude receipts to almost 1 000 m^3/d from virtually nil last year, as they experimented with heavy crude feedstock, deliveries of mainly heavy crude oil to TMPL's Westridge marine terminal (which accounted for 12% of movements) for export by tanker to such diverse destinations as Tacoma, Wash., the Gulf Coast (via the Panama Canal) and the Orient at 3 200 m3/d, were only about two-thirds of last year's first quarter level.

As of March 1, 1989, new tariff rates were being applied to crude petroleum movements on the TMPL system. The new tariffs were about 8.5% higher than 1988 average levels and were implemented mainly to cover the costs of TMPL's 1989-1990 expansion project. The expansion will permit the pipeline to transport 6 000 m^3/d of heavy crude oil to export markets while maintaining shipments of light crude to Vancouver refineries and refined products to Kamloops. The basic toll for light crude oil deliveries from Edmonton to Burnaby rose to $6.72/$m^3$.

4.2 Interprovincial Pipe Line

Total Interprovincial Pipe Line (IPL) deliveries of crude oil and other hydrocarbons, including petroleum products and natural gas liquids (NGLs), during the first quarter of 1989 averaged 239 000 m^3/d, 3% less than for the same quarter a year earlier. This drop was the result of a decrease in deliveries to all markets except Ontario.

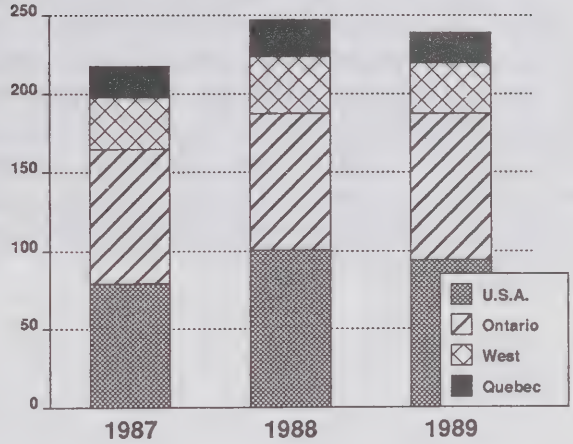
As a percent of total IPL deliveries, crude oil accounted for approximately 90% with petroleum products and NGLs making up the balance. The mix of light/heavy crude deliveries remained relatively unchanged from the previous year, while synthetic crude movements nearly doubled to 5%.

Sixty percent of IPL deliveries were destined for Canadian markets with most of the remainder delivered to the U.S. mid-west. Despite a first-quarter increase in petroleum product consumption in all regions except the Prairies, total domestic deliveries decreased slightly to 145 000 m^3/d while IPL deliveries to the United States, fell by 6% to 95 000 m^3/d, the lowest level in two years.

Ontario was the only domestic market to register an increase in deliveries. Deliveries were up 7% to 93 000 m^3/d compared with the same period a year earlier. Prairie refinery deliveries fell by 11% to 33 000 m^3/d. Lower regional petroleum product consumption and lower shipments of crude oil to the Co-op refinery because of the start-up of the Newgrade upgrader contributed to the decline. Quebec deliveries averaged 19 000 m^3/d, down 16% but were compensated for by a significant increase in crude and product imports. Refiners also drew down inventories.

IPL remained marginally short of capacity throughout the first quarter despite significant capacity additions since deregulation. As a result of maintenance work and other factors, IPL throughput declined from the first quarter of 1988. Capacity constraint problems, which reflected a number of factors, are expected to continue throughout 1989, especially during the typically high demand period of June through September. (For more details on pipeline apportionment see Section 3)

Figure 4.2
Total IPL Deliveries
000 m^3/d



IPL has applied to the National Energy Board to revise its pipeline tolls, effective July 16, 1989 to cover increases in the cost of service for the year 1989. The increase in tolls is proposed for a number of reasons, including lower forecast deliveries than approved under the original 1989 tariff application (October, 1988), increased operating costs, and the introduction of the new Federal Large Corporations Tax effective June 1, 1989. The net revenue requirement to cover these costs for the year is about \$2.3 million. If the toll revision is approved, the basic toll on the Canadian portion of the IPL system, from Edmonton to Sarnia will rise by about 5.5% to \$3.66/m^3 for the last 5 1/2 months of 1989.

4.3 Montreal Pipeline Utilization

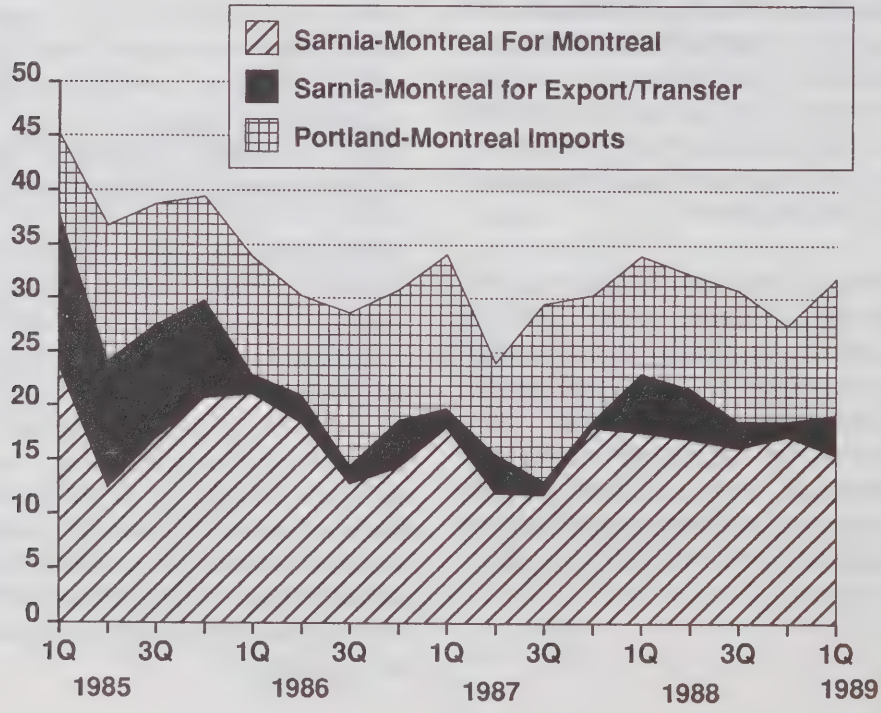
Total pipeline deliveries of crude oil and equivalent to Montreal refiners during the first quarter of 1989 averaged 31 900 m^3/d, down 2 400 m^3/d or 6% from the same period a year earlier. Total domestic deliveries via the Sarnia-Montreal portion of the IPL system averaged 19 300 m^3/d, 3 800 m^3/d less than a year ago while imports through the Portland Pipe Line increased by 1 700 m^3/d, to 12 600 m^3/d. Of the total domestic deliveries, about 4 000 m^3/d were for transshipment through Montreal to the export market or for transfer to Atlantic region refiners. This compares with 6 000 m^3/d in the first quarter of 1988, when more heavy crude was available for export.

Despite greater capacity on the IPL system, Montreal refiners have had periodic difficulty acquiring all the domestic feedstocks they were prepared to take. First quarter deliveries where somewhat restricted reflecting weather and technical constraints. To meet increased petroleum product demand, Montreal refiners turned to the import market for additional crude (despite an apparent significant domestic crude price advantage over imports) and petroleum product supplies. Montreal refiners also drew down crude and petroleum product stocks. (For more information relating to stocks and imports see Sections 2 and 5.)

The total composition of Sarnia-Montreal deliveries changed from the same period a year earlier. As a percentage of total IPL deliveries, light crude oil fell by 15 percentage points to 60%. Heavy crude deliveries increased from a 16% share to 32%, of which nearly one-third was exported (mainly to the U.S. Gulf Coast). Partially processed deliveries remained unchanged at about 8%.

The pipeline utilization rate of the Sarnia-Montreal portion of the IPL for the first quarter of 1989 averaged 32%, two percentage points lower than the first quarter of 1988. Over the same period, the Portland-Montreal system utilization rate increased by six percentage points to 42%. Appendix I illustrates the location and throughput capacities of major crude oil pipelines in Canada.

Figure 4.3.1
Crude Oil Deliveries to Montreal
000 m^3/d



5. Exports and Imports

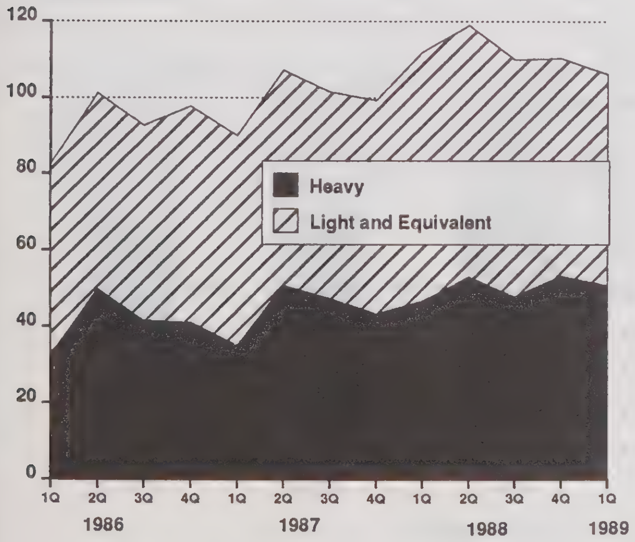
5.1 Crude Oil Exports

- *Tighter supply conditions and increased Canadian demand contributed to a decline in Canadian crude oil exports.*

Total crude oil exports for the first quarter of 1989 averaged 106 000 m^3/d, about 6 000 m^3/d or 5% less than the same period a year earlier. This was the first period-over-period decline since deregulation (1985). Of this volume exports to the United States decreased by 3 000 m^3/d to 105 000 m^3/d. Offshore exports to such diverse locations as Japan and Thailand fell by two-thirds, on small volumes, to 1 200 m^3/d.

As a percentage of total Canadian crude oil production, first-quarter exports represented about 38% of total production (heavy production, 68%; light and equivalent 26%), down two percentage points from last year. Exports were split at a ratio of 52:48 between heavy and light crudes compared with a 58:42 ratio a year earlier. In volumetric terms, exports of heavy crudes decreased by almost 10 000 m^3/d (15%) to 55 000 m^3/d, while light and equivalent crudes increased by 3 900 m^3/d (8%), to 51 000 m^3/d.

Figure 5.1.1
Crude Oil Exports
000 m^3/d



The drop in exports reflected slightly lower production, increased domestic demand for crude, in particular for heavy crudes, as well as weather and technical constraints on the IPL system. Deliveries to the U.S. midwest, Petroleum Administration for Defense (PAD) District II, were also restricted by a U.S. government-imposed operating restriction on an IPL - connected pipeline. In the case of heavy crude, the Newgrade upgrader added about 3 to 4 000 m^3/d to heavy crude demand in the Prairies. As well there was an inventory drawdown of 5 000 m^3/d in 1988 which did not occur in 1989.

With respect to light crude, despite a decline in production, exports were higher as compared to a year earlier because of the switchover from light to heavy crude feedstock at the Co-Op refinery which freed up some light crude for export.

As illustrated by Table 5.1.1 the bulk of Canadian crude oil exports were delivered to U.S. PAD Districts II and IV. PAD District II deliveries averaged 79 000 m^3/d, 5 000 m^3/d (5%) less than the same period last year. Heavy crude oil receipts fell by 5 700 m^3/d to 47 000 m^3/d while light crudes increased by 1 100 m^3/d to 32 400 m^3/d.

Table 5.1.1
Crude Oil Exports by Destination
(000 m^3/d)

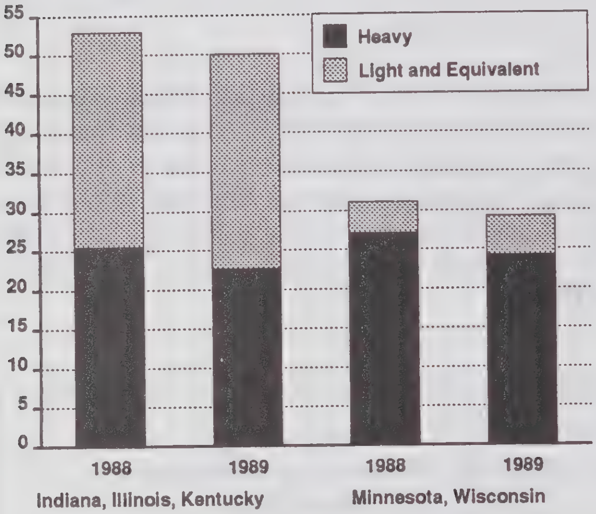
	Light		Heavy		Total	
	1988	1989	1988	1989	1988	1989
United States PAD Districts*						
I	7.6	7.8	0.8	1.1	8.4	8.9
II	31.3	32.4	52.7	47.0	84.0	79.4
III	0.0	0.0	3.8	2.4	3.8	2.4
IV	6.1	8.5	3.5	3.3	9.6	11.8
V	1.4	2.1	0.4	0.3	1.8	2.4
Total U.S.	**46.4**	**50.8**	**61.2**	**54.1**	**107.6**	**104.9**
Offshore	0.5	0.0	3.7	1.2	4.2	1.2
Total	**46.9**	**50.8**	**64.9**	**55.3**	**111.8**	**106.1**

**Petroleum Administration for Defense (PAD) Districts. See Appendix IV*

PAD District II exports were concentrated in the Indiana, Illinois and Kentucky refining district where total first-quarter receipts averaged 50 000 m^3/d, down 3 000 m^3/d (6%) from a year earlier. The Chicago, Illinois area accounted for the largest share of Canadian crude oil deliveries and registered the largest proportion of the year-over-year decline. Deliveries of heavy crudes to the district decreased by 11%.

Figure 5.1.2
Crude Oil Exports to PAD District II by Refining District

000 m^3/d



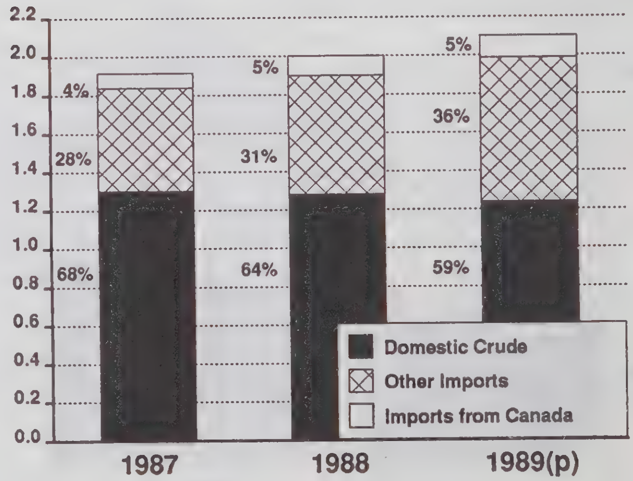
While PAD District II registered the largest decrease in the receipt of Canadian crudes, most other PAD Districts with the exception of PAD District III maintained or improved their level of receipts. Exports to Canada's second largest U.S. market, PAD District IV, the Montana/Wyoming area, averaged 11 800 m^3/d, up 2 200 m^3/d (23%) from the same period last year. As a result, the Rangeland pipeline delivery system operated at close to capacity throughout the quarter.

Although offshore exports declined, reflecting less crude availability, deliveries by tanker accounted for 4% of totals exports (compared with 8% in the first quarter 1988). All of PAD District III, and some PAD District I and V receipts were by tanker.

According to the U.S. Department of Energy, total crude oil imports (excluding Strategic Petroleum Reserve imports) for the first quarter of 1989 averaged 846 000 m^3/d, up 14% from the same period last year. Of this volume, imports of Canadian crude represented 12%, the third largest source of imported crude behind Saudi Arabia (23%) and Mexico (14%).

Crude oil imports as a percentage of U.S. refinery demand for crude (including domestic inputs), for the first quarter of 1989, amounted to 42%. As illustrated in Figure 5.1.3 Canada's share of this refinery demand (over the period under review), remained at about the 5% level, relatively unchanged since late 1987. However, the 'other' importers share increased significantly, to 36%, from 28% in 1987. Given that Canadian crude oil production is at capacity levels and there has been little growth in output since mid 1988, it is to be expected that U.S. incremental demand would be met by other countries in the short run. In addition, the increase in 'other' imports, reflects to a certain extent, declining indigenous production and high product demand, in areas such as the U.S. east coast (PAD District I) and Texas/Louisiana Gulf Coast (PAD District III), which are not readily accessible (other than by tanker) to Canadian crude.

Figure 5.1.3
U.S. Refinery Inputs
PAD District I to IV
(First Quarter)
million m^3/d



p = provisional

5.2 Crude Oil Imports

Canadian refiners imported 75 800 m^3/d of foreign crude during the first quarter of 1989, an increase of only 700 m^3/d (or 1%) over the same period a year earlier. Barring unforeseen product export opportunities or strong domestic sales, imports are expected to remain relatively steady throughout 1989.

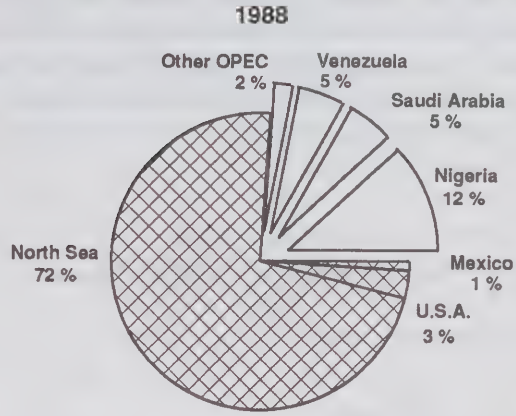
In the first quarter, there was a significant shift from non-OPEC to OPEC crude sources, in part because the share of North Sea imports was "higher-than-normal" in the first quarter of 1988. Also production of North Sea crude was disrupted during the first quarter of 1989 because of a series of accidents.

Imports from OPEC countries increased by 49%, to 26 300 m^3/d, representing a 35% market share of total Canadian import requirements, up 12 percentage points from the same period last year. West Africa and Saudi Arabia were the largest OPEC suppliers capturing a 15% and 12% share of Canadian imports, respectively.

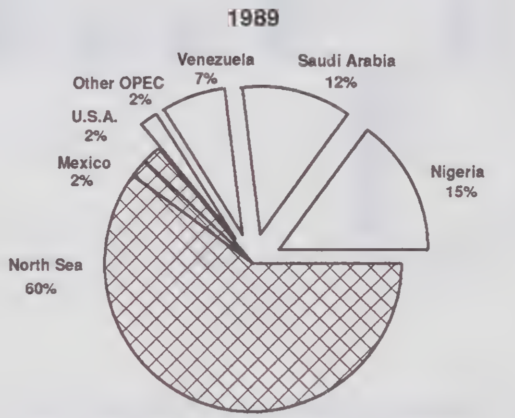
Non-OPEC crude receipts declined by 14% to 49 500 m^3/d. The North Sea continued to account for the majority of foreign receipts with a 60% share of all imports. This level was 9 000 m^3/d (or 17%) lower than the first quarter of 1988. Mexican imports rose to 1 800 m^3/d, compared with only 800 m^3/d last year.

On a regional basis, foreign shipments to the Atlantic and Ontario at 46 000 m^3/d and 1 700 m^3/d respectively were down only slightly. In Quebec imports rose 6% to 28 000 m^3/d.

Figure 5.2
Sources of Crude Oil Imports



Total 75 000 m /d
Non-OPEC 76% OPEC 24%

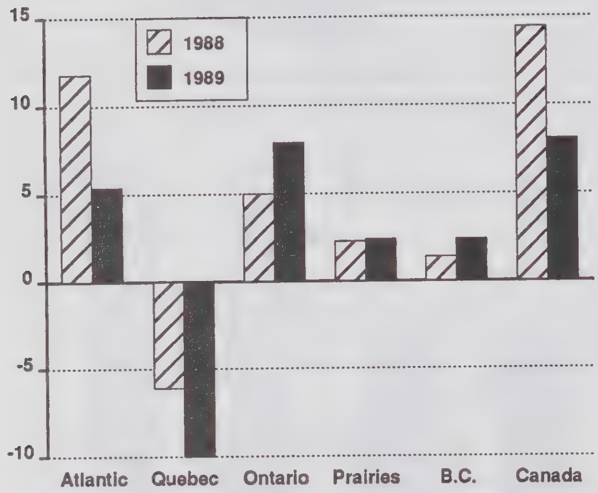


Total 76 000 m /d
Non-OPEC 65% OPEC 35%

5.3 Petroleum Product Trade

As a result of a sharp increase in product imports into Quebec and a decline in exports from the Atlantic (see Section 2) the net product export position in the first quarter 1989 fell by 6 000 m^3/d, to 8 000 m^3/d, compared with the first quarter of 1988.

Figure 5.3.1
Net Petroleum Product Trade
000 m^3/d

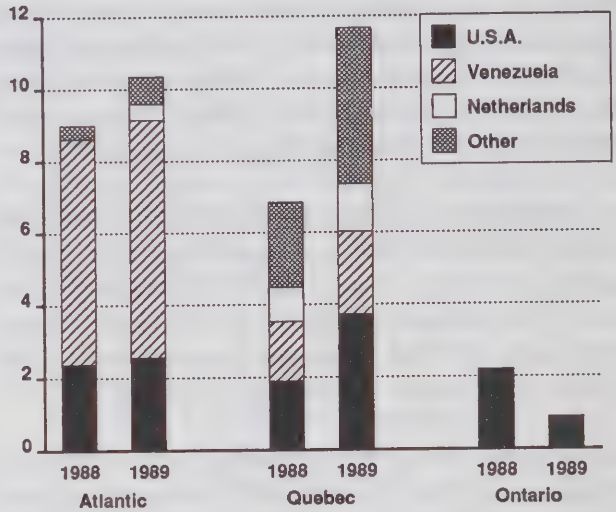


Quebec product imports were 60% higher than the year before, while exports fell. As a result the product trade deficit in Quebec widened to 10 000 m^3/d.

With respect to petroleum product imports, total imports into the Atlantic, Quebec and Ontario were up 20% reflecting the large jump in Quebec imports. Figure 5.3.2 outlines imports into these regions by countries of origin. While the number of countries and market share varies between regions, the largest source of imports for the three regions combined is Venezuela with a 40% share of the market, followed by the United States with 30%.

Much of the imports from Venezuela are of heavy fuel for electricity generation in the Atlantic. In contrast, Quebec imports are more evenly distributed among the main products, and there is a large number of source countries. In Ontario however, virtually all product imports originate in the United States, given the proximity of southern Ontario to the heavily populated areas of central and eastern United States.

Figure 5.3.2
Sources of Petroleum Product Imports
(First Quarter)
000 m^3/d



On the export side, total refinery exports, at about 36 000 m^3/d, represented close to 14% of total throughput. As shown in Table 5.3, 95% of Canadian exports of main petroleum products, including partially processed oil, are to the United States, with 75% of those exports to the northeastern states.

Table 5.3
Main Petroleum Product Exports to the United States
(First Quarter)

U.S. PAD Districts	1988	1989
	000 m^3/d	
I	24.3	22.1
II	2.9	3.1
III	0.6	1.7
IV	0.9	0.6
V	2.0	2.3
Total	**30.7**	**29.8**

Total U.S. imports of main petroleum products and partially processed oil in the first quarter of 1989 were about 300 000 m^3/d, with Canada accounting for approximately 10%. The Canadian market share however varies widely among products and among regions. For example Canada makes up in the vicinity of 20% of U.S. middle distillate imports, but less than 5% of heavy fuel imports. On a regional basis Canada provides about 10% of PAD District I imports, which, in turn, account for three-quarters of all U.S. product imports. On the other hand, product imports into PAD District II and IV are relatively small; however, Canada is the sole source for PAD District IV, and has an 85% import market share in PAD District II.

Although U.S. product imports are forecast to continue to increase, given current refinery capacity and high utilization rates in Canada, and the potential for further growth in domestic consumption, it is unlikely that there is much room for incremental growth in Canadian product exports to the United States.

6. Energy Trade Balance

- *Higher domestic demand and a relatively mild winter contributed to a reduction in the energy trade surplus.*

6.1 International

The energy trade balance fell on several fronts in the first quarter of 1989 compared with the first quarter of 1988. Mainly as a result of a decline in the volume of exports to the United States our trade surplus was lower in natural gas, electricity, uranium, liquified petroleum gases, and crude oil. Only the trade position in coal, where exports are primarily to countries other than the United States improved.

The energy surplus, at $1.9 billion, was about $0.3 billion less than the same period in 1988. The decline would have been greater had oil prices not risen throughout the quarter. The surplus position improved by more than $0.4 billion from the fourth quarter of 1988, reversing the downward trend of the three previous quarters.

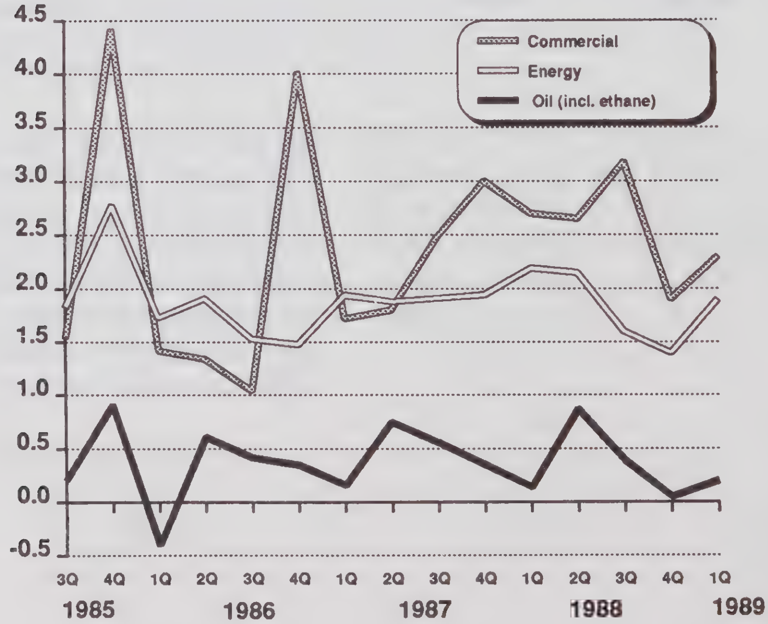
6.2 United States

As shown in figure 6.2, since about the third quarter of 1987, Canada's energy trade surplus with the United States has been on a slight decline. The only real growth has been in natural gas, with the largest declines in electricity and oil.

There are a number of factors which have contributed to the deterioration in the surplus. Throughout much of 1988 oil prices were declining and, since mid-1988, the volume of crude oil exported has also been falling. While crude oil prices turned upward in the first quarter of 1989, volumes continued to fall. As a result, the first quarter 1989 crude surplus dropped 6% to $0.9 billion, compared with the first quarter of 1988.

The decline in the electricity surplus over the last two years was primarily as a result of higher-than-expected growth in Canadian consumption, leaving less surplus electricity available for export.

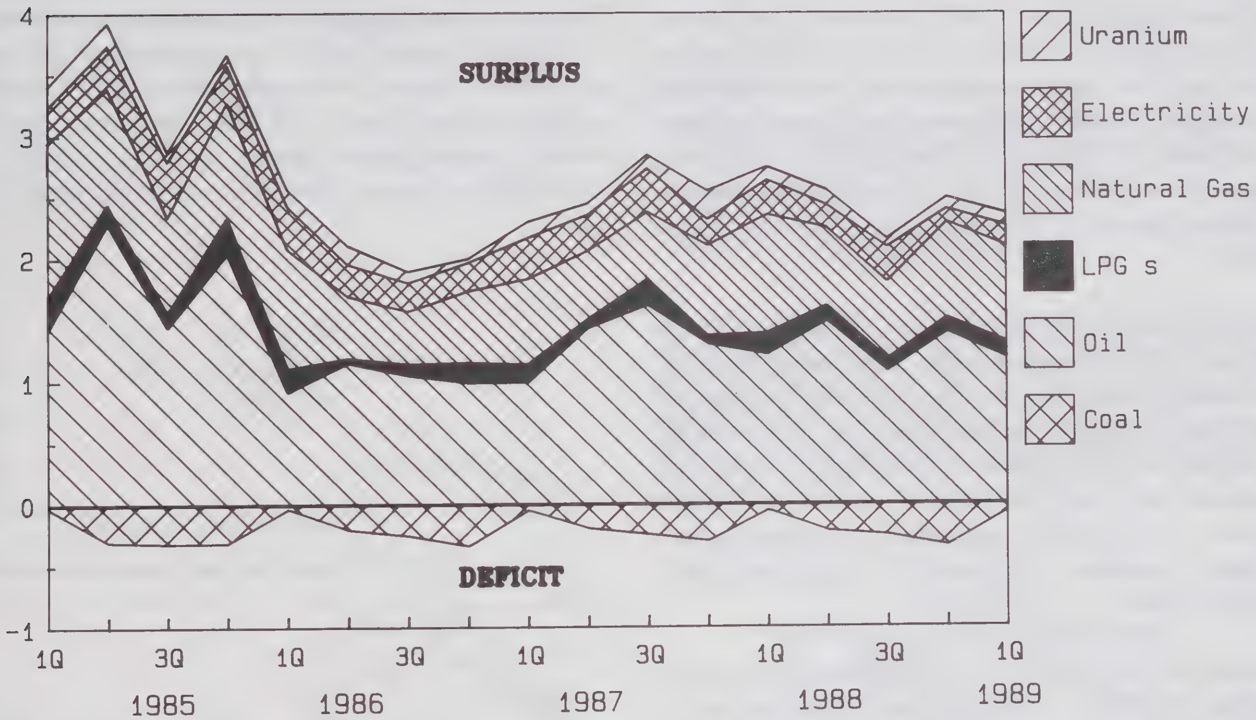
Figure 6.1
Oil and Energy Trade Balance
$ CAN (Billion)



The natural gas surplus had grown significantly in 1987 and 1988 because of deregulation and strong U.S. demand. However on a year-over-year basis there was a decline in the first quarter of 1989, in part, reflecting pipeline bottlenecks and a warmer winter this year.

In total the energy surplus with the United States fell about 10% in the first quarter, to $2.3 billion. Crude oil and natural gas accounted for 40% and 35% respectively, of the total surplus.

Figure 6.2
Net Energy Commodity Trade with the U.S. (Value)
$ CAN (billions)



7. Prices

- *Crude oil prices rose more than 20% in the first quarter, reflecting OPEC cohesion and a series of accidents in the international oil market.*

- *In Canada, gasoline prices moved up slightly, with the largest increases occurring in the Prairies.*

7.1 International Crude Oil Prices

During the first quarter of 1989, the world oil market was surprisingly strong. Crude oil prices began the year riding a wave of optimism engendered by the successful November 1988 OPEC agreement and, except for a brief pause early in February, continued to strengthen throughout the first quarter. From January 1 until the end of March the price of WTI rose about $3.50/bbl to around $20/bbl.

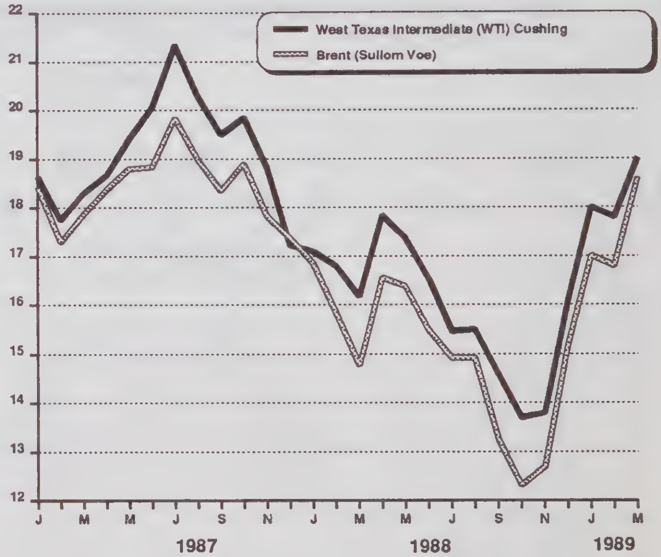
The significant first quarter crude oil price recovery surprised many oil analysts who pointed to numerous unpredictable events as providing the main impetus for higher prices, rather than sound oil market fundamentals. Nevertheless, the strength of international crude oil prices over the quarter can be attributed to a wide range of factors which, when combined with a number of unforeseen accidents, contributed to a psychologically buoyant market.

Crude oil supply over the first quarter was affected by a number of events. The absolute reduction of 2.4 MMB/D in OPEC crude oil output to 19.9 MMB/D was seen as a positive first step, with most members basically adhering to their production quotas. This was followed by a series of accidents which resulted in further declines in U.K. North Sea output and disrupted supplies of light crude oil. As well, in February there was an agreement by independent oil producers (IPEC) to reduce exports by almost 300 MB/D. This gave the market a psychological boost even if the volume specified was regarded as insignificant. The other major disruption came with the Alaska Valdez oil spill disaster which interrupted normal Alaskan crude oil production for almost two weeks.

In conjunction with these supply restrictions there were also reports of higher world-wide oil consumption. Fourth quarter 1988 world oil demand increased by 4.6% (excluding CPEs). This helped minimize the oil stock overhang that had been expected to flood the market in early 1989. First quarter 1989 oil demand continued to grow, albeit at a slower rate than in the fourth quarter of 1988.

Together these factors contributed to a positive market atmosphere that helped push prices to levels not seen since late 1987. WTI crude oil prices averaged $17.95/bbl in January (an increase of $1.95/bbl over the December average), held fairly steady in February at $17.85/bbl, although OPEC overproduction did cause prices to fall slightly early in the month, before climbing to $19.35/bbl in March. U.K. Brent crude oil prices followed a similar pattern, averaging $17.10, $16.85 and $18.60/bbl in January, February and March, respectively.

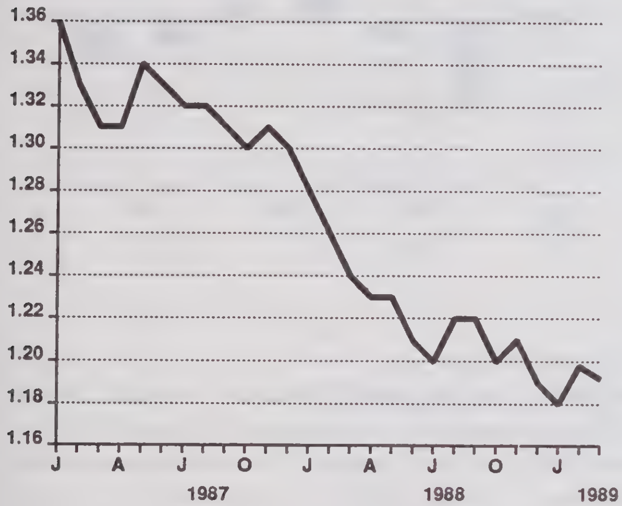
Figure 7.1
Crude Oil Prices (FOB)
$US/bbl



7.2 Domestic Crude Oil Prices

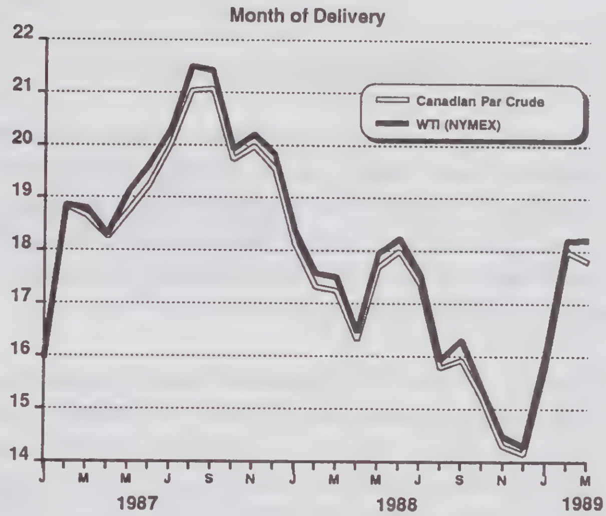
During the first quarter of 1989, light Canadian crude oil posted prices averaged $20.55 per barrel, an increase of $4.10 from the average of fourth quarter 1988 prices. The increase is primarily attributed to the international oil price increase of about US$3.60 per barrel (equivalent to about CDN$4.30 per barrel). The strengthening of the Canadian dollar vis-à-vis the American dollar reduced the oil price increase by about $0.25 per barrel.

Figure 7.2.1
Canada/U.S. Exchange Rates



Canadian light crude oil prices followed the trend set by international crudes, primarily the U.S. benchmark crude West Texas Intermediate (WTI). Figure 7.2.2. illustrates the close relationship between prices for WTI and Canadian crude, after adjustments for delivery times to Chicago. The differential between those crudes, in Chicago, increased from about US$0.18 per barrel in 1988, to US$0.29 during the first quarter of 1989.

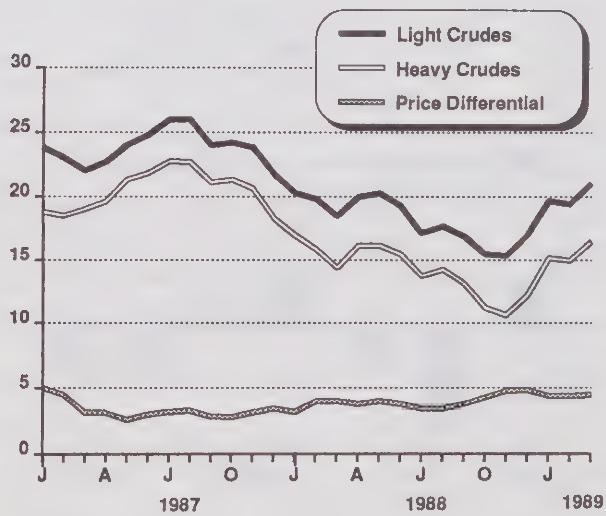
Figure 7.2.2
Canadian Par Crude vs WTI (NYMEX*)
$US/bbl



* *New York Mercantile Exchange*

Figure 7.2.3 compares actual prices for Alberta light and heavy crude oil, purchased for use in Canada at main trunk line injection stations. On average, reported light conventional crude oil quality during the first quarter of 1989 was 37.3° API, 0.39 % sulphur, and blends of heavy crude were 24.4° API, 2.55 % sulphur.

Figure 7.2.3
Comparison of Domestic Light and Heavy Crudes
Actual Purchase Prices - Alberta
$CDN/bbl



The differential between Canadian light and heavy crude prices, during the first quarter, was about $4.45 per barrel, $0.17 lower than in the fourth quarter.

7.3 Crude Oil Export Revenues

This section provides an update to the review first presented in the third quarter of 1988 edition of the Canadian Oil Market, with an additional breakout between light and heavy crude exports and the inclusion of the impact of changes in transportation costs on producers' export earnings.

Figures 7.3.1 and 7.3.2 show that both light and heavy crude export revenues have declined since deregulation, despite a partial recovery in earnings in 1987. The decline in heavy crude export revenues has been almost twice as large as that applying to light crude oil. Semi-annual earnings from foreign sales of heavy crude amounted to $1.6 billion in the second half of 1985, whereas they were only half this amount in the second half of 1988, implying a reduction in revenues of around $800 million. Over the same period, light crude oil export earnings were reduced by $400 million, from $1.4 billion to $1 billion.

Figure 7.3.1
Producers' Light Crude Oil Export Netback Revenues
(Semi-Annual)
$ CAN (Billions)

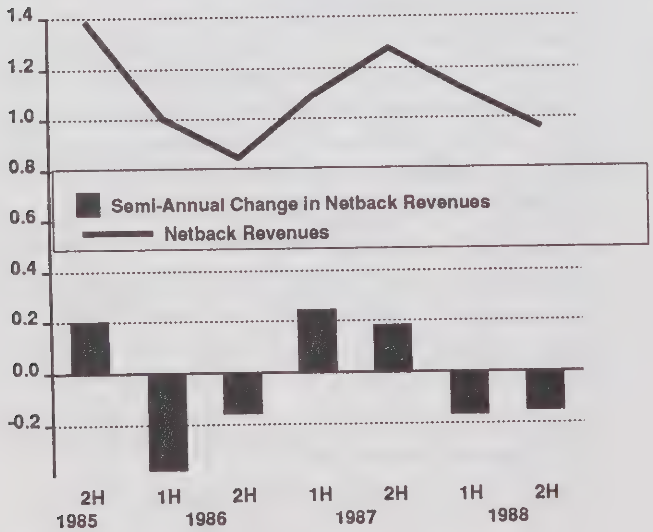
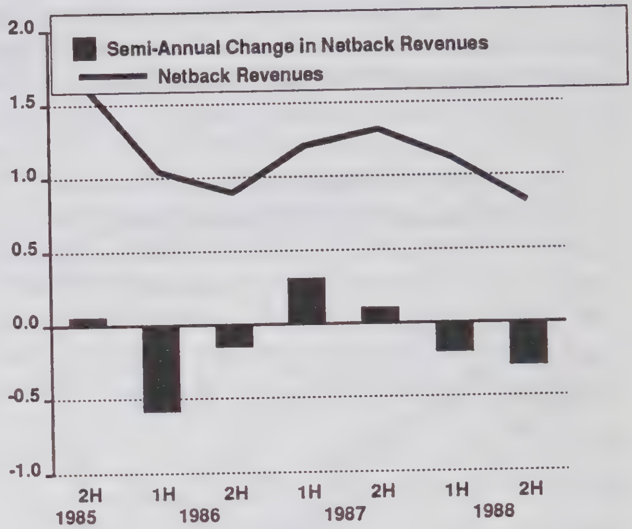


Figure 7.3.2
Producers' Heavy Crude Oil Export Netback Revenues
(Semi-Annual)
$ CAN (Billions)



Despite the significant difference in the overall rates of decline, light and heavy crude export revenues have consistently fluctuated in unison, if not to the same extent, over time. The bar charts in the lower half of figures 7.3.1 and 7.3.2 which highlight these revenue changes vis-à-vis the previous half-year period, reveal this similar pattern of change.

Since changes in export revenues are a product of the underlying changes in export volumes and prices (in U.S. dollars) and the U.S.-Canadian dollar exchange rate, it is revealing to look at the dollar impacts that movements in these three variables have had on export revenues. These are shown in figures 7.3.3 and 7.3.4.

Figure 7.3.3
Impact of Changes in Price, Volume and the Exchange Rate on Light Crude Oil Netback Revenues
$ CAN (Billions)

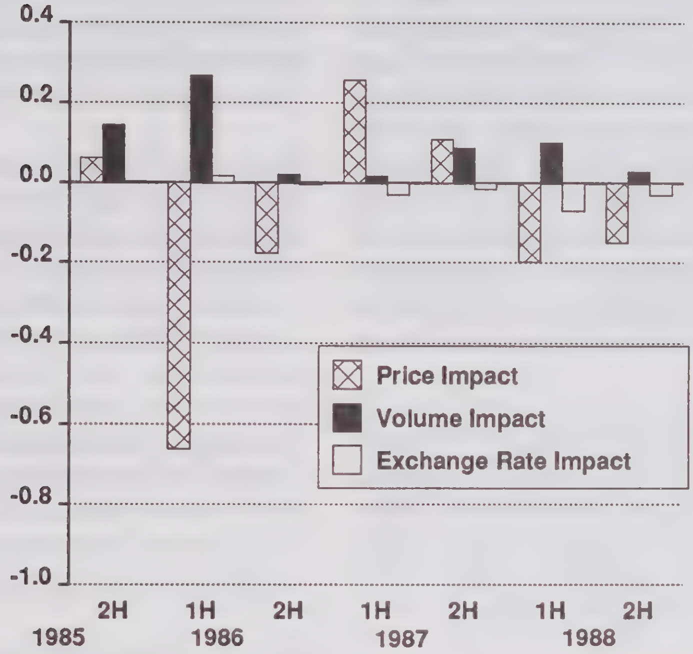
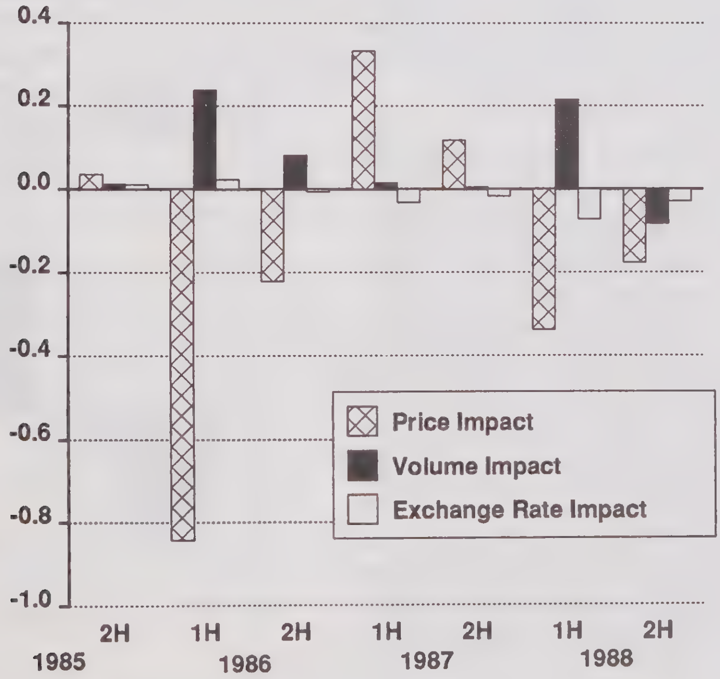


Figure 7.3.4
Impact of Changes in Price, Volume and the Exchange Rate on Heavy Crude Oil Netback Revenues
$ CAN (Billions)



In the latter half of 1985, after deregulation came into effect, total crude oil export netback revenues rose by 9% to $3 billion semi-annually. Three quarters of this increase was the result of the rise in prices and exports of light crude oil with the remainder attributable to relatively minor upward impacts of the average exchange rate and heavy crude oil prices and exports. The subsequently sharp decline in export revenues to $2.1 billion in the first half of 1986 was strictly the result of the 40% and 45% drop in the export prices of light and heavy crude respectively, as in fact, export volumes increased significantly while the exchange rate continued to remain relatively steady during this period. Export revenues continued to decline, to $1.7 billion in the second half of 1986, following a further drop in export prices, although now at a slower rate.

Earnings partially recovered in 1987 reaching $2.6 billion dollars in the latter half of the year. As in 1986, this had more to do with movements in export prices, in this case upwards, as opposed to changes in the quantities exported or the exchange rate. Also, as in 1986, most of the change occurred in the first half of the year.

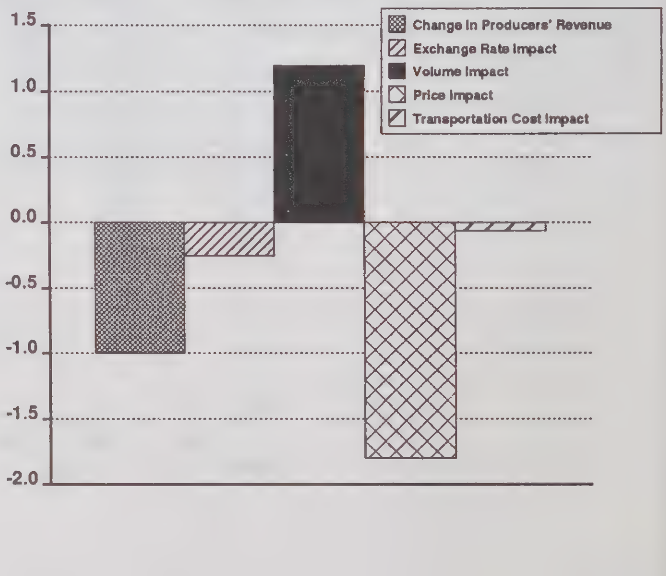
1988 saw producers'revenues resume their downward course. Prior to last year there had been relatively little change in the exchange rate since deregulation and therefore it had played only a subsidiary role in the decline of export revenues. In 1985 the price of the U.S. dollar averaged $1.37 Canadian while by 1987 it was only down 4 cents to $1.33. However, in 1988 the average exchange rate fell by 10 cents to $1.23, contributing substantially to the decline in netback revenues.

Last year was also distinct from the two preceding years in other respects. First, the rate of decline in export revenues remained relatively steady throughout the year with the decline in the second half of 1988 in fact about 20% greater than that of the first. Second, for the first time since deregulation there was a volumetric reduction, of almost 10% to 60 000 m^3/d, in heavy crude oil exports in the latter half of the year, which exacerbated the decline in export earnings. Up to then progressive increases in exports of both light and heavy crude oil had moderated the potentially much larger decline in producers' revenues that would have otherwise occurred in the absence of such increases. Thus light crude export revenues would have been about 40% lower in the latter half of 1988 than they actually were had there not been the post-deregulation export increases, while heavy crude revenues would have seen a 30% reduction. As it was, heavy crude oil producers saw their lowest semi-annual export earnings to date, and light crude oil producers their second lowest (their lowest being in the second half of 1986). It is doubtful, at least for the short to medium term, whether producers will be able to increase volumes exported in an effort to maintain export revenues.

Transportation costs entailed in delivering the crude oil to the export market, insofar as they are paid for by the producers (the assumption made in this review), as opposed to the consignees, obviously also impact on netback revenues. These costs, although important in the context of producers' net revenues or profits, nevertheless have had only a minor impact on gross netback revenues. As a percentage of selling prices, transportation charges have gradually increased from about 3% in 1985 to 9% in 1988 for both light and heavy crude oil exports. Mostly, this reflects the overall decline in crude export prices in the face of relatively steady pipeline and tanker transportation charges.

Overall, the total decline in producers' semi-annual export revenues in the three and a half year period approached $1.0 billion. The price impact accounted for -1.8 billion dollars; the volume impact, +1.1 billion; the exchange rate impact, -250 million; and the impact of increases in transportation costs was -65 million, or about 7% of the total revenue change.

Figure 7.3.5
Overall Impact of Changes in Price, Volume, Exchange Rate and Transportation Costs
$ CAN (Billions)



7.4 Petroleum Product Prices

Price Trends

The average Canadian price for regular unleaded gasoline at self-serve outlets increased by 1.9 cents per litre, or 2%, during the first quarter of 1989 (March 28, 1989 vs December 27, 1988).

Prices increased in all but two of ten major centres across Canada. In Charlottetown, the average price remained the same, while in Winnipeg it declined an average 0.6 cents per litre. In the other major centres, price increases ranged from 0.9 cents per litre in Halifax to 4.4 cents per litre in Calgary.

Retail diesel prices increased 0.5 cents per litre on a Canada average basis, 80% of the increase occurring during the last three weeks of March. Price changes ranged from a 0.2 cent per litre decrease in Saint John, N.B., to a 1.1 cent per litre increase in Toronto.

Average residential furnace oil prices increased 1.1 cents per litre. The price stayed the same in three of the ten centres. In the remaining centres, the prices increased from 0.3 cents per litre in St. John's, Nfld., Saint John, N.B., and Vancouver to 4.4 cents per litre in Montreal. Despite the approximate 18% rise in the consumer price in Montreal, residents of Montreal still enjoy some of lowest furnace oil prices in the country.

Consumption Taxes on Petroleum Products

The federal excise tax remained unchanged during the first quarter of 1989. The tax is currently 6.5 cents per litre on all grades of gasoline and 4.0 cents per litre on diesel oil (see Appendix V).

The federal sales tax on petroleum products is reviewed quarterly and adjusted according to the Industrial Product Price Index. During the first quarter of 1989, the review process resulted in a net sales tax decrease of 0.1 cent per litre on all grades of gasoline and diesel.

Table 7.4
Average Regular Unleaded Gasoline Prices
Self-Serve
1988-1989

	1988				1989	%
	March	**June**	**Sept.**	**Dec.**	**March**	**Change 12 mo .**
	(cents per litre)					
St. John's (NFLD)	52.8	3.9	52.5	50.9	52.2	- 1.1
Charlottetown	51.6	52.3	50.9	49.6	49.6	-3.9
Halifax *	49.9	50.9	49.5	47.9	48.8	-2.2
Saint John (N.B.)	*49.7	50.7	49.8	48.6	50.2	1.0
Montreal	56.0	57.1	55.8	54.0	55.0	-1.8
Toronto	46.1	48.6	46.5	45.9	48.5	5.2
Winnipeg	43.6	42.1	45.9	44.5	43.9	0.7
Regina	48.0	45.6	45.6	39.2	43.3	9.8
Calgary	44.2	41.1	41.6	37.0	41.4	-6.3
Vancouver	48.9	48.8	48.8	47.3	49.5	1.2
Canadian Average	**49.4**	**50.1**	**49.3**	**47.6**	**49.5**	**0.2**
Consumption taxes included:						
Federal	8.9	9.9	9.9	9.9	9.8	10.1
Provincial	9.4	9.8	9.9	9.8	9.8	4.2

** Full-serve*

In January, the weights assigned to the provincial taxes were adjusted. These changes were offset by tax increases in two of the provinces and the average provincial sales tax on all grades of gasoline remained at 10.1 cents per litre on March 1, 1989.

In New Brunswick, the ad valorem rate on gasoline and diesel was increased from 20% and 23% to 24.5% and 31.5%, respectively. These changes resulted in tax increases of between 1.5 and 2.8 cents per litre. In British Columbia, the tax on gasoline and diesel increased 0.8 cents per litre as a result of their quarterly review process.

On March 30, 1989, New Brunswick and Saskatchewan tabled budgets which changed taxes on some petroleum products. In New Brunswick a 2.2 cent per litre surcharge was levied on regular leaded gasoline, effective March 31. This increased the tax on regular leaded gasoline to 11.6 cents per litre. The taxes on regular unleaded and premium unleaded remained at 9.9 and 10.7 cents per litre, respectively. New Brunswick had been the only province with a higher tax on unleaded gasolines.

Effective March 31, Saskatchewan increased its tax on gasolines and diesel by 3 cents per litre and imposed a surcharge of 2 cents per litre on leaded gasoline. This brings the tax on unleaded gasoline and diesel fuel to 10 cents per litre while the tax on leaded gasoline rises to 12 cents per litre.

New Brunswick and Saskatchewan are the fourth and fifth provinces, joining Ontario,Manitoba and British Columbia, to implement a higher tax on leaded gasolines as compared to the unleaded grades. One of the main reasons for the taxation changes has been to accelerate the switch to unleaded fuels by removing the price incentive for using leaded gas.

Canada vs United States

The average retail price for all grades of motor gasoline in Canada and the United States increased 1.2 and 0.7 cents per litre, respectively, during the first quarter of 1989. In March 1989 the difference between Canadian and American average gasoline prices was 16.8 cents per litre. Higher consumption taxes in Canada account for more than 70% of the differential. The balance is attributable to higher refining and marketing costs and/or profits in Canada.

Figure 7.4.1
Average Retail Price of Motor Gasoline
Canada vs United States
cents per litre

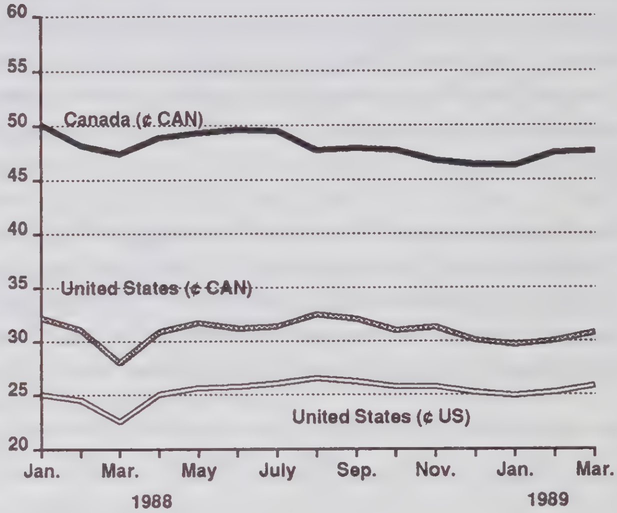
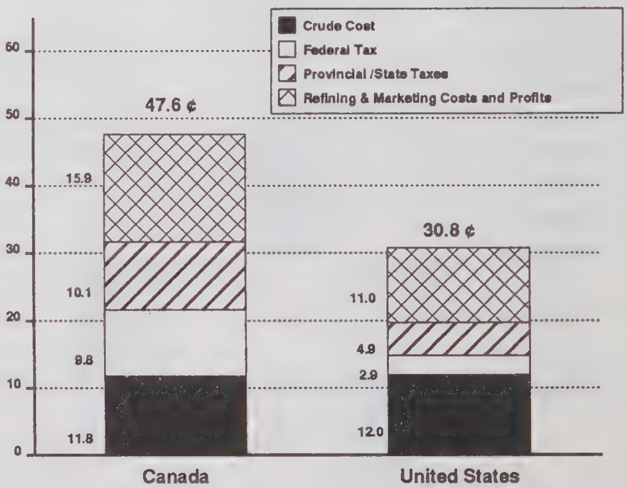


Figure 7.4.2
Breakdown of Average Pump Prices
(March 1989)
$CAN/litre



Exchange rate = 1.1953

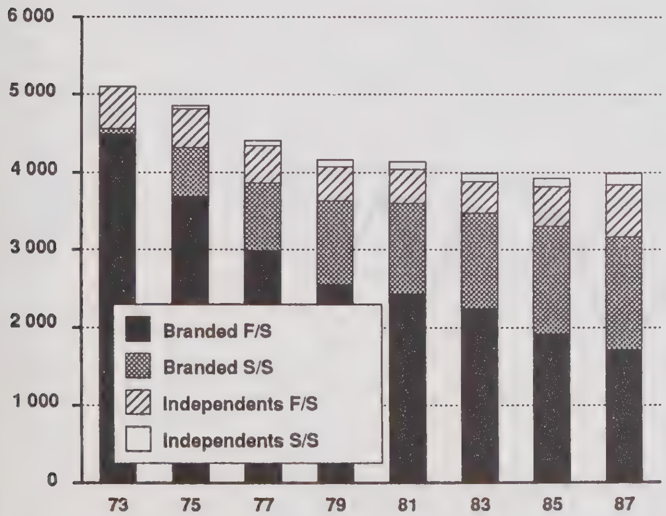
7.5 Review of the Canadian Retail Gasoline Market

- the number of retail outlets declined throughout most of the period from 1973 to 1987;
- independents' share of total outlets increased at the expense of refiner-brands; and
- the proportion of self-serve outlets increased.

The Canadian retail gasoline market has undergone major changes over the last 15 years, with the introduction and evolution of self-serve stations being one of the more dominant factors. Figure 8.5 outlines some of the changes that have taken place since 1973 in the motor gasoline outlet populations of 10 major retail gasoline markets across Canada.

The graph focuses on the rationalization of the outlet population; the changes in the share of retail outlets between refiner-marketers and independent private-brand marketers (see Glossary for definitions); and the timing and extent to which self-serve stations have replaced full-serve outlets.

Figure 7.5
Trends in Retail Gasoline Marketing
Number of Outlets



S/S = Self Serve *F/S = Full Serve*

While the total population declined steadily over the 1973 to 87 period, 80% of the rationalization occurred during the first 7 years.

Over the 15-year period, refiner-marketers reduced their outlets by 31% while the independents increased theirs by 52%. As a result, the independent marketers doubled their share of the retail outlet population from 10% in 1973 to 20% in 1987.

Self-serve outlets represented an increasing proportion of the outlet population throughout the period. By 1987, 40% of the stations in the 10 centres studied were self-serve, accounting for 48% of all gasoline sales.

The independent marketers, however, have been slower to convert to self-serve stations. One of the marketing strategies often used by independents is to offer full-serve gasoline at a price slightly below the self-serve price of refiner-branded stations. In fact, many of the new outlets opened by the independent sector in recent years have continued to offer full-service. As a result, in 1987 only 18% of independent outlets were self-serve.

On a regional basis, there have been some contrasting trends. Rationalization in central Canada (Québec and Ontario) was the most significant contributor to the overall decline in the outlet population. Although the independents made gains in their share of the outlet population in all regions of the country, in eastern Canada the independent sector still remains quite small.

Note : a more detailed regional and/or major city review is available from the Canadian Oil Markets and Trade Division upon request.

8. Drilling Rig Activity

- *Drilling activity, which is usually at its peak during the winter, declined more than 30% in the first quarter as industry lacked confidence that the first quarter increase in crude oil prices could be sustained.*

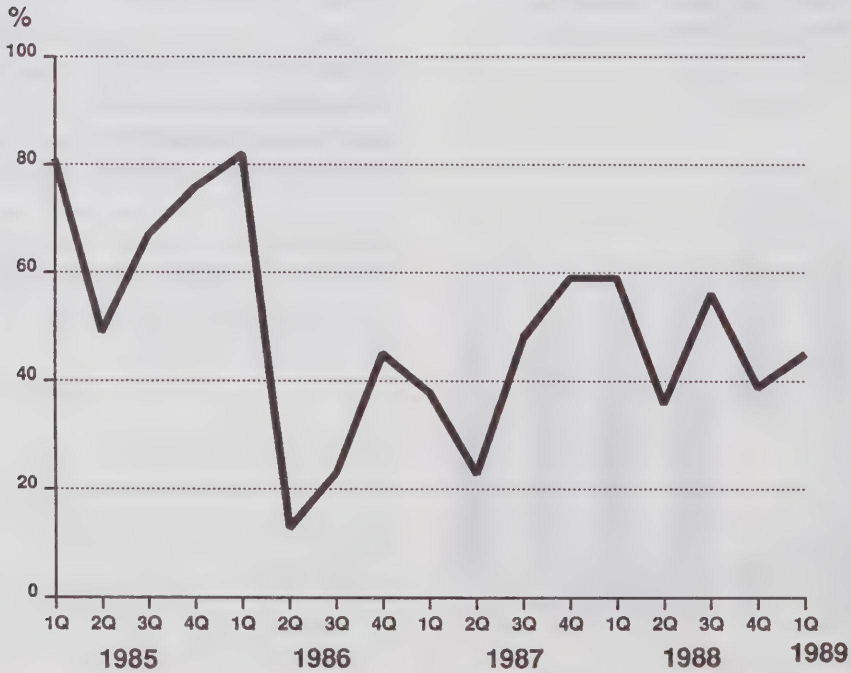
Despite an increase of over $ US 3/bbl in world oil prices since November, 1988, drilling rig activity during the first quarter of 1989 only averaged 240 active rigs, down 30% from a year ago, and represented a rig utilization rate of only 45%. Exploration activity was lowest in January when only 190 rigs were active. Exploration picked up in February and March however, with about 270 rigs, or almost half of all available rigs, active.

The first-quarter slump was apparently the result of a combination of factors. In the summer and fall of 1988, industry undertook more oil exploration than they might otherwise have in order to take advantage of government drilling incentives (i.e. CEDIP) that were scheduled to be reduced by half in the fourth quarter of 1988. It subsequently curtailed drilling activity in the fourth quarter and the first quarter of 1989. Also, industry is skeptical about whether the oil price recovery will persist and therefore has been reluctant to commit funds to exploration, preferring to adopt a wait-and-see attitude.

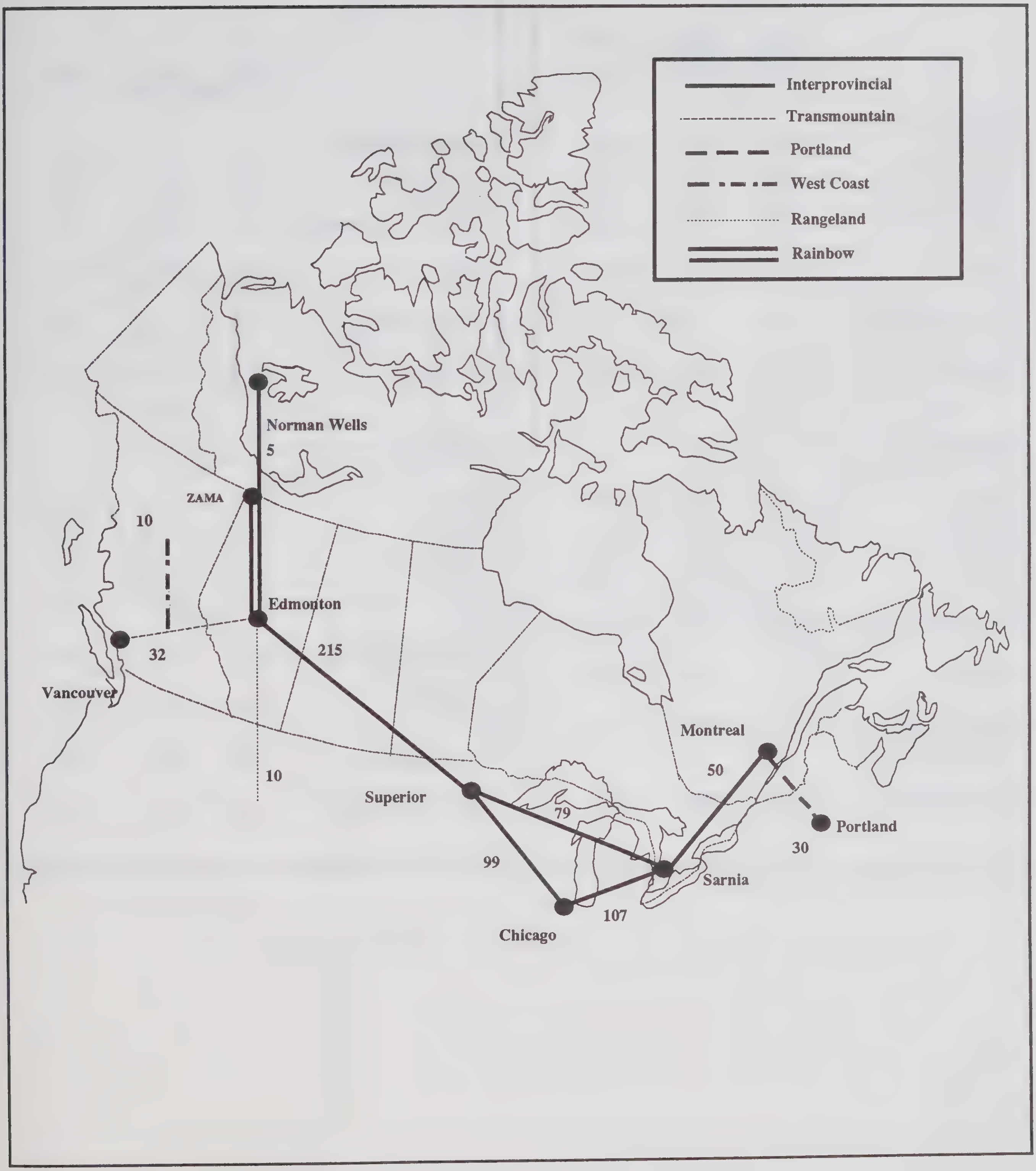
Even if higher prices persist, there are other developments within the industry which may dampen drilling and capital expenditures. The higher number of mergers over the past few years likely has had a negative impact. It appears that, at least in the short-term, a merged company may engage in less drilling activity than would the two companies prior to the merger.

In addition some companies, particularly the smaller ones, have had trouble raising funds because of the 1987 stock market crash, higher interest rates, and tighter flow-through share provisions. An improvement in the business environment, along with higher prices, may be needed to get activity back to pre-1986 levels.

Figure 8.1
Drilling Rig Activity
% Utilization



Appendix I
Major Crude Oil Pipelines in Canada
Location and Capacities
000 m^3/d



Appendix II
Light Crude Oil and Equivalent Production and Disposition

(First Quarter)

	1987	1988	1989
	---------- (000 m^3/d)	-----------	
PRODUCTION			
Alberta	118.2	136.1	130.9
Other Regions	22.7	23.2	22.8
Synthetic	31.7	26.1	28.9
Pentanes Plus	18.4	20.0	18.6
Total	**191.0**	**205.4**	**201.2**
Inv. Draw/(Build)	2.0	3.7	5.8
Net Supply	193.0	209.1	207.0
DEMAND			
Quebec	12.5	13.2	9.6
Ontario	66.3	63.8	68.3
Prairies	47.6	53.8	50.3
B.C.	19.7	19.2	16.7
Domestic Demand	146.1	150.0	144.9
Exports	35.1	46.8	49.0
Diluent for Heavy (excl. recycled)	11.8	12.3	13.1
Total Demand	**193.0**	**209.1**	**207.0**

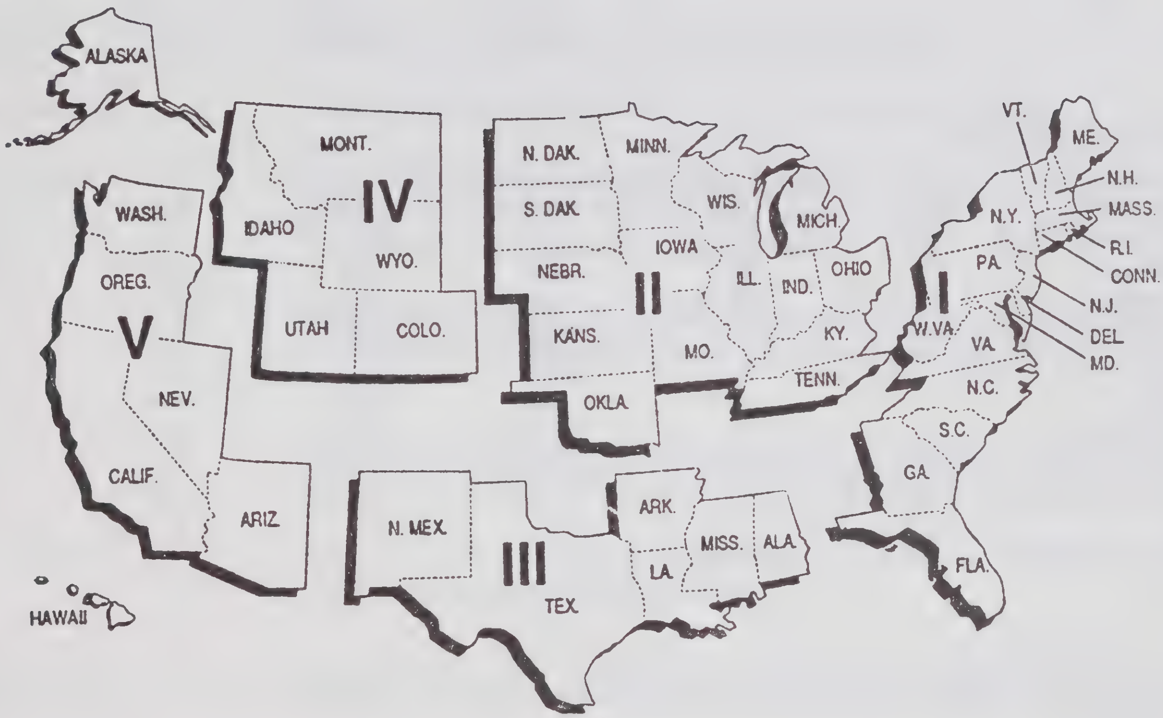
Appendix III
Heavy Crude Oil Production and Disposition

(First Quarter)

	1987	1988	1989
	-------- (000 m^3/d)	---------	
PRODUCTION			
Conventional	42.0	44.2	44.9
Bitumen	17.1	20.5	20.2
Diluent (incl. recycled)	12.6	13.4	13.4
Total	**71.7**	**78.1**	**78.5**
Inv. Draw/(Build)	0.4	4.8	0.2
Net Supply	72.1	82.9	78.7
DEMAND			
Atlantic	0.4	1.1	0.0
Quebec	3.6	3.9	4.9
Ontario	9.4	9.0	9.9
Prairies	3.7	3.7	5.3
B.C.	0.1	0.1	0.8
Domestic Demand	17.2	17.8	20.9
Exports	54.9	65.1	57.8
Total Demand	**72.1**	**82.9**	**78.7**
Recycled Diluent	0.8	1.1	0.7

Appendix IV

U.S. Petroleum Administration for Defense (PAD) District



Appendix V
Consumption Taxes on Petroleum Products
(March 1, 1989)

	Ad valorem		Gasoline			
	Mogas	Diesel	Reg L	Reg UL	Prem UL	Diesel
	(%)		(cents per litre)			
FEDERAL TAXES						
Sales			3.29*	3.29*	3.38*	2.54*
Excise			6.5	6.5	6.5	4.0
PROVINCIAL TAXES						
Newfoundland	22	26	9.3	9.3	9.3	11.5
Prince Edward Island	20	23	8.3	8.3	8.3	8.7*
Nova Scotia	20	21	8.2	8.2	8.2	8.5
New Brunswick	24.5*	31.5*	9.4*	9.9*	10.7*	11.2*
Quebec (b)			14.4	14.4	14.4	12.45
Ontario			12.3	9.3	9.3	9.9
Manitoba			9.8	8.0	8.0	9.9
Saskatchewan			7.0	7.0	7.0	7.0
Alberta			5.0	5.0	5.0	5.0
British Columbia (c)	22.5 (d)		9.79*	7.79*	7.79*	8.23*
Yukon			4.2	4.2	4.2	5.2
Northwest Territories	17	(e)	8.4	8.4	8.4	7.1

(a) *The gasoline tax is reduced by 1.5 cents per litre in the region between the Quebec border and Red Bay in Labrador.*

(b) *Reduced by varying amounts in certain remote areas and within 20 kilometers of the provincial and U.S. borders.*

(c) *Additional transit tax of 3.0 cents per litre in Vancouver.*

(d) *This applies to unleaded gasoline. Taxes on leaded gasoline and diesel fuel are 2.0 and 0.44 cents per litre higher, respectively, than the unleaded tax.*

(e) *85% of gasoline tax.*

* *Changed since last quarter.*

Glossary

Bitumen	A naturally occurring viscous mixture composed mainly of hydrocarbons heavier than pentane, which may contain sulphur compounds and which in its natural state is not recoverable at a commercial rate through a well.
Conventional areas	Those areas of Canada that have a long history of hydrocarbon production. Conventional areas are also referred to as nonfrontier areas.
Crude oil and equivalent	Includes crude oil, synthetic crude, oil produced from oil sands plants, and condensate.
Feedstock	Raw material supplied to a refinery or petrochemical plant.
Heavy crude oil	Loosely applied, crude oils with a low API gravity (high density).
Independents	Independent owners of gasoline outlets or chains of outlets, who purchase product, generally from a refiner, and retail under their own brand (e.g. Canadian Tire, Domo, Suny's, Pay-Less). Included in this category are brands of Independents who have contractual arrangements with refiners for the management of all or part of their business operations. Also included in this category are a few second-brand outlets which are owned by Refiner-marketers but which cannot be identified from available data.
In situ recovery	With reference to oil sands deposits, the use of techniques to recover bitumen without the necessity of mining the sands.
Light crude oil	Crude oil with a high API gravity (low density). Generally includes all crude oil and equivalent hydrocarbons not included under heavy crude oil.
Majors	Companies which refine crude and are essentially nation-wide product marketers (ESSO, PETRO-CANADA, SHELL, TEXACO).
Natural gas liquids	Those hydrocarbon components recovered from raw natural gas as liquids by processing through extraction plants, or recovered from field separations, scrubbers or other gathering facilities. Includes the hydrocarbon components ethane, propane, butane and pentanes plus, or a combination thereof.
Oil sands	Deposits of sands and other rock aggregate that contain bitumen.
Pentanes plus	Also referred to as condensate. A volatile hydrocarbon liquid composed primarily of pentanes and heavier hydrocarbons. Generally a by-product obtained from the production and processing of natural gas.

Productive capacity	The estimated production level that could be achieved, unrestricted by demand, but restricted by reservoir performance, well density and well capacity, oil sands mining capacity, field processing and pipeline capacity.
Regional refiners	Companies which refine crude and limit their product marketing operations to a specific geographic region of Canada (Irving, Ultramar, Sunoco, Husky, Chevron, Turbo, Consumers' Co-Op).
Refiner-marketers	Major and Regional refiners.
Refiner-brand outlets	A gasoline station selling product under the brand name of one of the Refiner-marketers.
Shut-in capacity	The unused production capability of currently producing oil and gas wells plus the total production capability of all shut-in oil and gas wells, regardless of whether or not they are connected to surface gathering and production facilities.
Synthetic crude oil	Crude oil produced by treatment in upgrading facilities designed to reduce the viscosity and sulphur content.

The Canadian Oil Market

Vol. V, No. 2, Second Quarter 1989

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Vol. V, No.2, Second Quarter 1989

Canadian Oil Markets and Trade Division
Energy Sector
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Table of Contents

Appendices

List of Figures

List of Tables

The Canadian Oil Market

Overview

- *Despite adequate pipeline capacity and strong demand, Alberta conventional light crude production in the second quarter was almost 6 000 m^3/d less than forecast capacity. Uncertainty about oil prices and very low drilling activity are two factors contributing to the decline in capacity.*

- *Industry and government forecasters have revised downwards their estimates of conventional Alberta light crude supply for the remainder of l989. Heavy crude capacity is expected to remain flat.*

- *There are early signs that the conventional light crude market in Canada (and the United States) may be shifting to a seller's market in the mid-west.*

- *Canadian refiner demand for domestic and imported crude continued strong. There was some movement to Canadian heavy crudes, while the increase in imports into Ontario and Quebec resulted from the declining availability of Canadian light, sweet crude.*

- *Seasonally-adjusted petroleum product consumption declined in the second quarter, after four quarters of growth. As a result of higher product prices and a slowdown in economic growth, product sales may have peaked.*

- *It also appears that both crude oil production and exports peaked in mid-1988, and will continue to decline for the short to medium term.*

- *Drilling rig activity, which is an indicator of the health of the upstream sector of the oil industry, was off substantially in the second quarter. Analysts do not expect any improvement for the balance of the year.*

- *Capital expenditure intentions remain unchanged from the beginning of the year. A shift in expenditures to the downstream sector is still anticipated.*

- *According to data compiled by the Canadian Petroleum Association, established oil reserves in Canada rose in 1988, but reserves in the key conventional category fell 3%.*

1 Domestic Demand

- *Rising product prices and a slowdown in the economy in the second quarter of 1989 appear to have led to a marginal decline in seasonally-adjusted refined product sales from the previous quarter.*

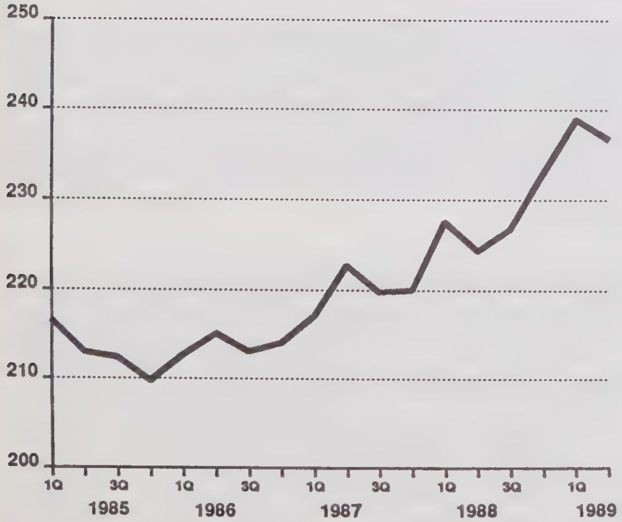
- *On a year-over-year basis, refined product consumption was up across all regions in the second quarter.*

- *Rising demand for heavy fuel oil accounted for about two-thirds of the increase in total product sales in the Atlantic between 1983 and 1988.*

1.1 Seasonally Adjusted

Averaging 237 000 m^3/d during the second quarter of 1989, seasonally adjusted sales of refined petroleum products in Canada were down about 1% from the previous quarter but were almost 4% higher than the 1988 annual average. As shown in the graph below, a second quarter drop in demand has occurred in three of the past five years.

Figure 1.1
Total Petroleum Product Consumption
(Seasonally Adjusted)
000 m^3/d



Last year's second quarter fall off may be partially explained by a first quarter inventory build by consumers in anticipation of the April 1, 1988 increase in the excise tax on motor fuels. The decline in product sales this year appears to have resulted from generally higher refined product prices that had risen in tandem with crude oil prices. The decline was also exacerbated by a slowdown in the rate of economic expansion. The lack of economic growth in the second quarter, per se, does not explain falling product demand since the gross domestic product did not decline. However, the absence of significant growth meant that the negative impact of higher prices on refined product demand was less likely to be offset.

Both motor gasoline and diesel fuel sales declined by 2% from the first quarter to 96 000 m^3/d and 47 000 m^3/d, respectively. Together these two transportation fuels now account for slightly over 60% of total product sales, on a seasonally adjusted basis.

Heavy fuel oil (HFO) over the course of a year typically accounts for about 10% of total product sales. Demand for HFO can be volatile, since it is sensitive to price competition from natural gas and electricity in fuel-switchable markets. It appears that industry, to some extent, did switch out of heavy fuel oil use into natural gas and electricity in response to declining natural gas and steady electricity prices. Whereas heavy fuel oil sales, at 24 000 m^3/d, were down 8%, preliminary data suggests that both natural gas and electricity sales were up during the second quarter, the former substantially so in the industrial sector.

Partially offsetting the declines in HFO and transportation fuel consumption were increased sales of light fuel oil and "other products". Light fuel oil demand, on a seasonally adjusted basis, was up 3%, to 22 0000 m^3/d, from the first quarter. Although light fuel oil has gradually been losing market share in the competition with natural gas in the residential heating market (its share of annually product sales now averages below 10%), its relatively strong growth this year was commensurate with the colder temperatures experienced this past heating season. "Other product" sales rebounded in the second quarter after falling off in the first, to capture a 20% market share with a 5% increase to 48 000 m^3/d.

The sharp downturn in the Canadian economy, in conjunction with recently higher prices, may not bode well for growth in sales of refined products in the short to medium term. Since bottoming out at the end of 1985, petroleum product consumption has followed a relatively steady growth path, such that by the first quarter of 1989 it had grown by almost 30 000 m^3/d. Growth could be maintained over this period largely because, at any particular time, at least one of its two key determinants, the levels of refined product prices and general economic activity, was moving in the right direction to stimulate higher demand. Thus, for example, although product prices rose throughout most of 1987, sales growth was sustained by the strong economic expansion that year. The somewhat sharper increase in sales in 1988 was the result of the two determinants acting in unison, with the economy continuing to expand at the same time as product prices fell.

However, the converse situation seems to have emerged in 1989: economic growth is down while product prices are up. Given the prospect that this situation will persist over the next several quarters, a protracted period of relatively stable refined product sales is likely to ensue. Canada's experience would then be similar to other industrialized countries where product consumption growth has been curtailed recently.

1.2 Regional Consumption

Actual consumption of refined products (i.e. before seasonal adjustments) across Canada averaged 229 000 m^3/d during the second quarter, about 5% higher than the level recorded for the same quarter last year.

Table 1.2
Petroleum Product Consumption
(Second Quarter)

	1988	1989	% Change
	000 m^3/d		
Atlantic	26.1	29.0	11.3
Quebec	46.4	48.1	3.6
Ontario	73.7	76.6	4.1
Prairies/Territories	47.7	49.3	3.3
British Columbia	24.1	25.9	7.8
CANADA	217.9	228.9	5.1

Sales in the Atlantic region, comprising 13% of the national total, were up 11% from last year, the highest year-over-year growth among all the regions. Two-thirds of the increase in the Atlantic was attributable to the over 25% rise in heavy fuel oil consumption. The incremental demand largely came from the region's electric power industry, which increased its use of HFO to make up for a drought-induced shortfall in hydro-generation. Sales of diesel fuel oil and "other products" also showed significant gains.

The growth rate in Quebec sales slowed to below 4% in the second quarter. The 35% increase in HFO consumption largely came from the region's thriving pulp and paper industry, and from other heavy industries which reverted back to HFO use once Hydro-Quebec's price incentives were phased out in mid-1988. The HFO increase was completely offset by a decline of 20% in "other products" sales. On the other hand, growth in gasoline sales remained strong at 7%. Quebec accounted for slightly over 20% of total refined product sales.

Although on a year-over-year basis, sales of HFO remained strong in eastern Canada for the aforementioned reasons, recent seasonally-adjusted monthly data suggest that demand may now be levelling off, if not declining, as HFO loses some of its relative price advantage to competing energy alternatives, and the economy slows.

A third of all product sales were in Ontario. Growth in Ontario consumption, at 4%, was only slightly better than Quebec's. While both gasoline and "other products" sales were up 6%, heavy fuel oil demand was down over 20%, possibly reflecting some switching by industry to natural gas.

The Prairie region continued to show the smallest gains in petroleum product consumption, reflecting the lingering effects of last year's drought and low oil prices on its economy. Nevertheless, diesel demand in the agricultural sector appears to have returned to more normal levels after the decline last year. The 10% increase in diesel fuel sales accounted for virtually all of the region's growth in product demand. The Prairies accounted for 22% of total sales in the second quarter.

British Columbia with an 11% market share continued to show strong growth in product demand, reflecting the relatively healthy state of the region's economy. Led by an 11% increase in motor gasoline consumption, aggregate sales were up 8% from last year.

Sales were up almost 7% in Japan as a result of its sustained economic growth. In particular, the strong demand for heavy fuel oil resulted from technical problems which reduced electricity supply generated from other sources.

1.3 International Oil Consumption

In relation to the same period last year, refined product consumption in the second quarter was up a mere 1% overall in the three major industrial regions included in Table 1.3. Collectively these three regions account for about 60% of refined product sales in the non-communist world. Canadian sales growth at 5% was thus comparatively robust.

Table 1.3
Petroleum Product Consumption
% Change 1988/1989*
(Second Quarter)

Product	Canada	U.S.A	Europe**	Japan
Motor Gasoline	4.9	-1.6	1.2	5.8
Middle Distillates	5.5	3.2	-4.9	7.2
Heavy Fuel Oil	17.1	7.1	1.1	9.0
Other Products	-0.3	-0.3	0.9	6.1
TOTAL	5.1	0.2	0.2	6.8

** Preliminary*
*** Comprises West Germany, Italy, France and the United Kingdom*

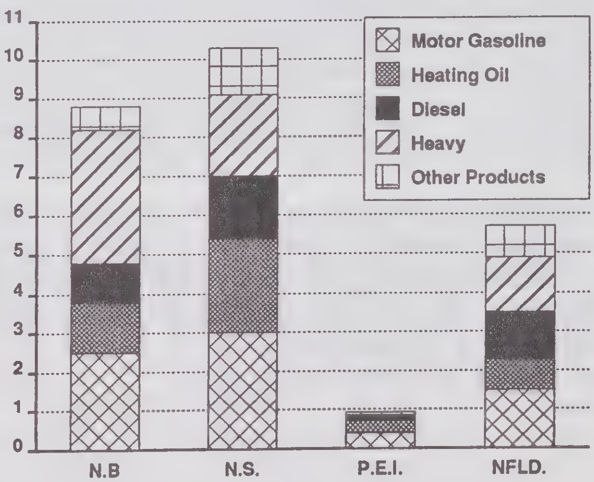
As in the previous quarter, aggregate sales in both the United States and Europe remained virtually flat. In the United States, respectable gains in middle distillate and HFO sales were to a large extent offset by a modest decline in motor gasoline demand in the wake of a 20% rise in its price.

In Europe, pronounced disparities in sales growth persisted between countries. Both Italy and the United Kingdom posted gains of 6% in product consumption while in France consumption was up only marginally. As in the first quarter, these increases were virtually nullified by a sharp reduction in West German sales. The 5% reduction in middle distillate demand in Europe was primarily the result of exceptionally mild weather which lowered heating oil sales.

1.4 Petroleum Product Sales in the Atlantic Provinces

The Atlantic provinces have collectively accounted for about 6% of Canada's gross domestic product and 9% of its population since the economic recovery which began in 1983. Over the same period from 12 to 14% of total refined product sales in Canada have been in the Atlantic. To explain the Atlantic region's disproportionately large share of product sales, it is revealing to disaggregate the region's total sales by product type and by province. Figure 1.4.1 illustrates average per diem sales by province and by product during the 1983-1988 period.

Figure 1.4.1
Average Petroleum Product Sales
(1983-1988)
000 m^3/d



Aggregating across provinces, the market share of motor gasoline averages 28%, diesel fuel 16%, light fuel oil 19%, heavy fuel oil 27% and "other products", 10%. On the basis of market share alone it would appear that, relatively speaking, the Atlantic region consumes

significantly less transportation fuel and "other products" than the rest of Canada, and significantly more light and heavy fuel oil. However, simply looking at market share is somewhat misleading in an inter-regional comparison as it fails to account for the above-average refined product consumption that is found in the Atlantic. Nor does it help to identify why overall product consumption in the region is so high to begin with.

A more meaningful comparison can be had by "normalizing" consumption on the basis of population i.e. by calculating and then comparing the rates of consumption for each product on a per capita basis for the Atlantic region and the rest of the country. Average per capita sales of motor gasoline and diesel fuel in the Atlantic turn out to be roughly comparable with the rest of the country, whereas consumption of "other products" remains below at about two-thirds the national rate. On the other hand, Atlantic sales of light and heavy fuel oil are respectively about three and four times higher per capita. It is the relatively higher demand for these two products which accounts for the high overall levels of refined product sales in the region.

The reasons behind the relatively high consumption of light and heavy fuel oil relate to the relative lack of available alternative energy commodities in the Atlantic specifically in the case of light fuel oil in the space heating sector, and heavy fuel oil in the electric power generation industry. The other regions rely more on natural gas, coal, nuclear and hydro-electric power to meet their electric power and heating requirements.

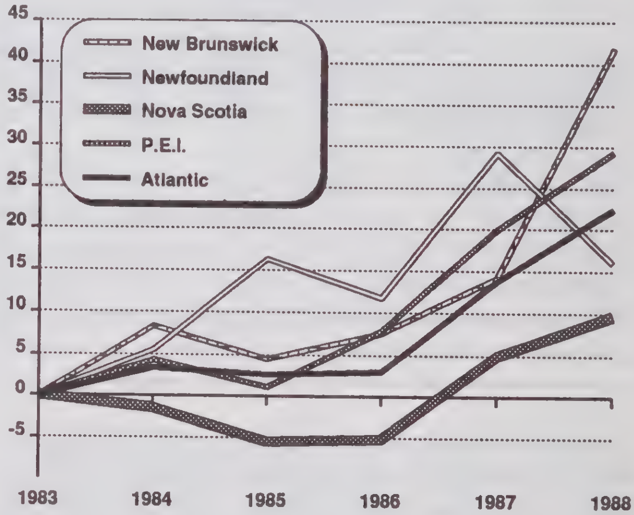
New Brunswick is particularly reliant on heavy fuel oil to generate electricity. Although only about a third of New Brunswick electric power generation is actually oil-based, this is still significantly higher than the 2% average for the country as a whole.

Figure 1.4.2 illustrates the annual percentage change in total product consumption by province from the base year 1983. Total refined product sales in the Atlantic grew by about 22% between 1983 and 1988 versus 6% for the nation as a whole. Heavy fuel oil recorded a 60% increase in sales over this period, accounting for almost two-thirds of the increase in total product demand, with higher sales in New Brunswick alone accounting for almost half of the increase. Most of the increase in consumption occurred in the last two years in response to hydro-electric generation shortfalls occasioned by low water levels.

Figure 1.4.2

Percentage Change in Total Product Consumption

% change from 1983



2 Refinery Utilization and Stocks

- *Refinery capacity utilization registered 83% in the second quarter, with the Prairies and Ontario recording increases.*

- *Closing stocks were 5% higher than the same period last year with 90% of the increase occurring in product stocks.*

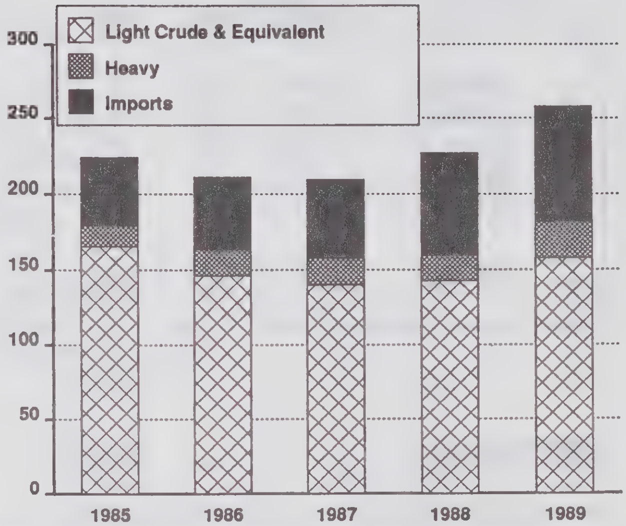
2.1 Refinery Utilization

Crude oil run to stills (including butanes and partially processed oils) during the second quarter of 1989 averaged 250 000 m^3/d, 7% or 16 000 m^3/d higher than the second quarter of 1988. As a result the national refinery utilization rate increased by five percentage points, to 83%.

Part of the increase in utilization was attributable to extended refinery maintenance programs last year, in both the Prairies and Ontario, which resulted in lower-than-normal refinery throughput during the second quarter of 1988. To meet product requirements refiners were forced to draw down stocks at about 14 000 m^3/d. During the second quarter of this year, with "normal" maintenance programs in effect, refiners built stocks at about 2 000 m^3/d.

Commensurate with the higher throughput, crude oil and equivalent receipts were up 13% from a year earlier. Domestic crude receipts increased by 13% to 182 000 m^3/d. Conventional crude oil increased by 3% to 113 000 m^3/d while synthetic crude and pentane plus volumes remained unchanged at 27 000 and 4 000 m^3/d respectively. The proportion of heavy crude oil receipts continued to increase as receipts jumped by over 40%, to 24 000 m^3/d. About half of this increase was attributable to the commissioning of the Newgrade upgrader. Crude oil imports were also higher by 13%.

Figure 2.1
Crude Oil and Equivalent Receipts at Canadian Refineries
(Second Quarter)
000 m^3/d



Receipts in the Prairies and Ontario were up 20% reflecting much higher crude throughput compared with last year. The Newgrade upgrader and some substitution of light crude by heavy crude contributed to an increase in heavy crude receipts. Refineries in British Columbia reduced their crude oil receipts by 5%, to 23 000 m^3/d. A 4 000 m^3/d reduction in light crude deliveries to British Columbia was partially offset by a doubling of semi-refined oil (to 5 000 m^3/d) shipped from Edmonton.

Despite increases in petroleum product demand, all other regions recorded reductions in refinery utilization. In the Atlantic region much of the decrease in crude runs reflected a 25% drop in product exports to markets along the U.S. Atlantic seaboard. Crude runs for the export market fell by 9 percentage points to 41% of throughtput when compared with a year earlier. Similarly, product exports from British Columbia declined by half.

In Quebec a decrease in crude runs corresponded to a 25% reduction in domestic feedstock receipts (excluding butanes and partially processed oils), although increased crude imports offset some of the decline. All of the decrease in feedstocks was recorded in the light crude oil category. Petroleum product imports increased by two-thirds relative to last year's level.

Table 2.1
Refinery Utilization
(Second Quarter)

	1987	1988	1989
		%	
Atlantic	64	83	77
Quebec	72	83	79
Ontario	76	73	86
Prairies	79	73	85
B.C.	87	92	87
Canada	75	78	83

1989 Outlook

Recent submissions to the National Energy Board indicate that refiners are planning to increase crude runs through to the end of the year. Throughput in 1989 is programmed to average 258 000 m^3/d, 3% above the 1988 level. All regions are scheduled to improve with the exception of British Columbia. The 1989 refinery utilization rate is expected to reach 85%, three percentage points higher than last year.

2.2 Stocks

Refined petroleum product and crude oil stocks at the end of the second quarter of 1989 registered 14.5 million cubic metres, 5% (or 725 000 m^3) higher than the same period last year. Petroleum product stocks increased by 6% to 11.6 million cubic metres, representing about 90% of the total stock change. Crude oil stocks increased by 2% to 2.9 million cubic metres.

Changes in crude oil stock levels during the second quarter were concentrated in Ontario and Quebec. Crude stocks in Ontario rose by 18% as refiners adjusted levels to meet rising product demand. In Quebec refiners drew down stocks by 12% as domestic feedstock deliveries declined. In the Atlantic region stocks rose by 8% reflecting an unusual drop in product exports.

Figure 2.2.1
Closing Crude Oil and Product Stocks in Canada

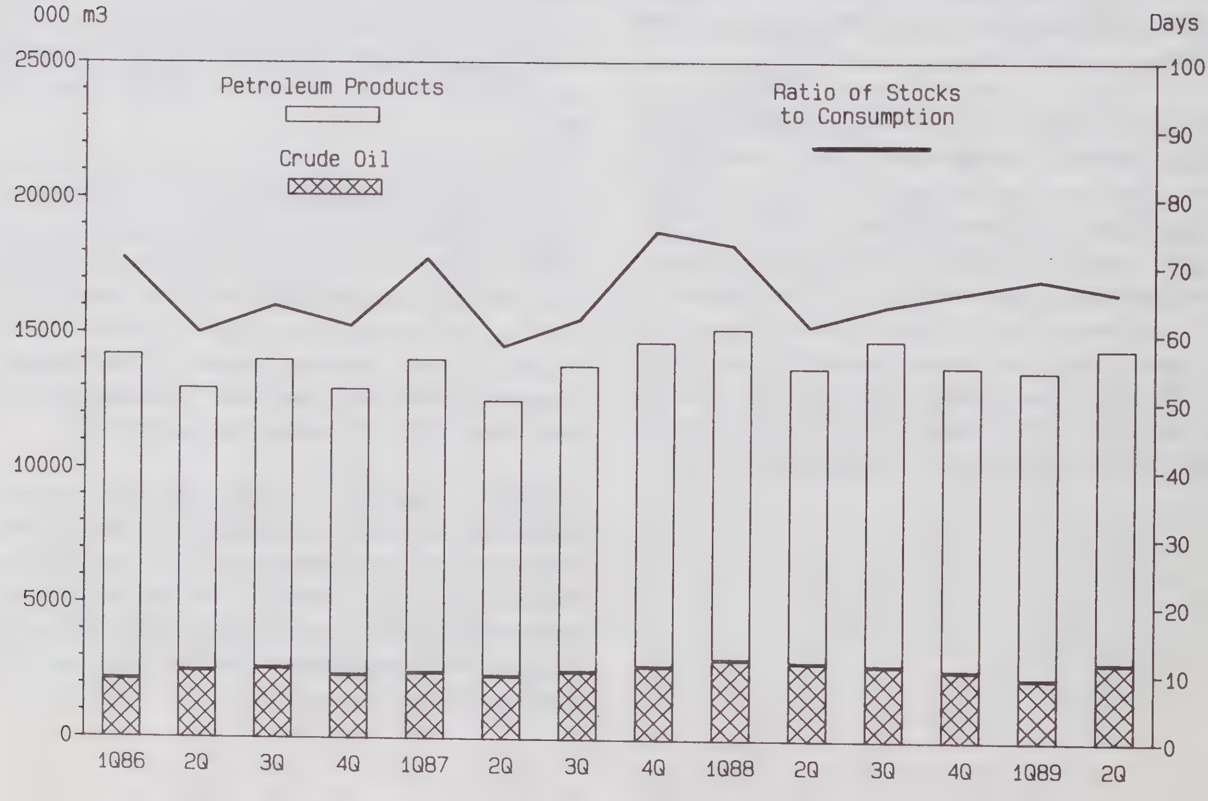


Table 2.2.1

Closing Inventories by Region

(June)

000 m^3/d

	1988 Crude	1988 Product	1989 Crude	1989 Product
Atlantic	1045	1675	1125	1790
Quebec	792	2094	699	2432
Ontario	598	3531	704	3632
Prairies	284	2423	273	2442
B.C.	110	1139	86	1236
Canada	2829	10897	2887	11564

Table 2.2.2

Ratio of Stocks to Consumption

End June

	Days					
	Crude			Product		
Years	**87**	**88**	**89**	**87**	**88**	**89**
Atlantic	33	42	27	71	67	68
Quebec	20	17	15	46	46	53
Ontario	6	8	10	41	46	50
Prairies	5	6	6	51	50	51
B.C.	4	4	3	43	40	48
Canada	11	13	13	47	48	53
Canada (excluding Atlantic)	9	9	9	41	49	51

The increase in petroleum product stocks, when compared with the second quarter of last year, was spread across all products with the exception of diesel fuel. Motor gasoline stocks led the way with a 6% increase, while stocks of other "main" petroleum products recorded less significant gains. Stocks of products in the "other products" category, such as jet fuel, petrochemicals and asphalt, increased by 17%.

All regions recorded increases in petroleum product stocks with Quebec registering the largest jump, up 16% from a year earlier. The second largest increase was recorded in the Atlantic region where product stocks increased by nearly 7%.

By the end of the quarter the ratio of stocks to consumption for petroleum products and crude oil represented about 66 days of forward consumption, up 5 days from a year earlier. If the Atlantic region is excluded from the ratio, because a large portion of shipments are directed to the export market and it is not pipeline-connected to Canadian crude sources, the ratio of stocks to consumption for the rest of Canada would have been 60 days, versus 58 days in 1988.

The stocks referenced above do not include estimates of crude oil held in pipeline tankage. If these stocks were included, the ratio of total stocks to consumption would increase by about 7 days to 73 days of forward consumption. This ratio is 7 days higher than the 66-day average for the Organization for Economic Cooperation and Development (OECD) countries. However, if public (government owned and entity stocks) were included, the OECD average would then increase to 95 days.

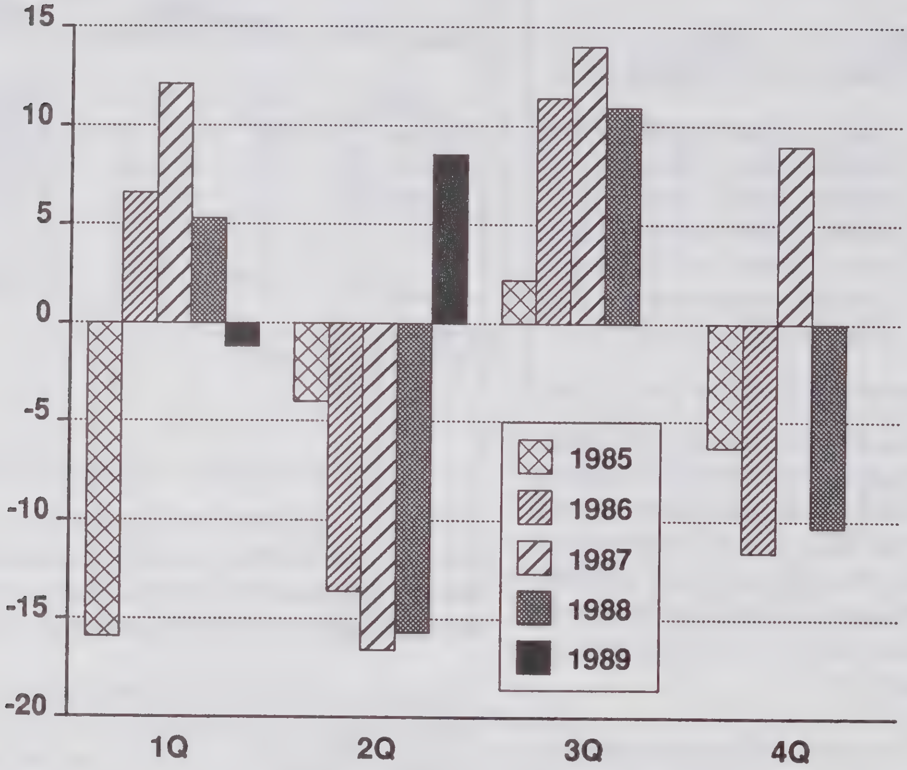
Canadian crude oil and petroleum product stock changes generally follow a traditional seasonal pattern. As illustrated by figure 2.2.2, stocks over the last five years, despite an absolute decline in the total stock level, have normally been built in the first and third quarters and drawn down during the second and fourth quarters.

The contradictory draw in the first quarter of 1985 can be attributed to refiners' rationalization of stock levels in anticipation of deregulation in June of 1985. The fourth quarter 1987 stock build reflects the reactivation of the Come-by-Chance refinery.

The counter-seasonal build in the second quarter of 1989, may have been because both product demand and exports were less than expected, while product imports were greater than expected. Also, as previously noted, refinery maintenance programs had been more extensive in previous years.

Figure 2.2.2
Crude Oil and Petroleum Product Stock Changes

000 m^3/d



3. Crude Oil Supply and Disposition

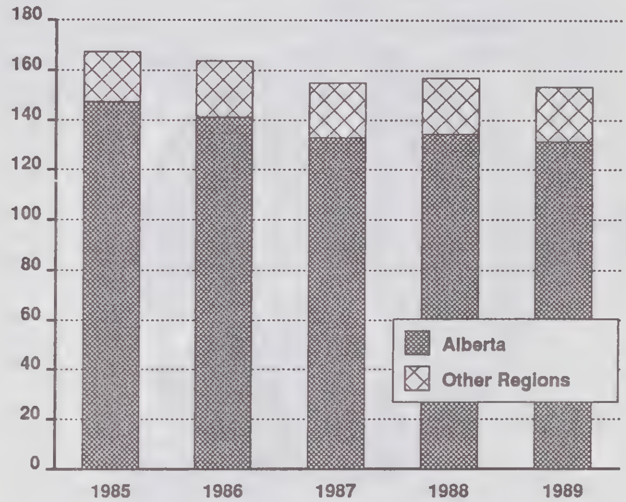
- *Uncertainty over crude oil prices and other factors have had a negative effect on crude oil output.*
- *Because of lower-than-expected production of conventional light crude, forecast capacity has been reduced for the remainder of 1989.*

3.1 Light Crude Oil and Equivalent Supply and Disposition

Conventional light crude oil productive capacity continued to decline in the second quarter of 1989 to 153 000 m^3/d, down 4 000 m^3/d or about 3% from the same quarter last year. All of the decline occurred in Alberta as the other producing regions collectively recorded a marginal increase in productive capacity. Alberta capacity at 131 000 m^3/d has declined 17 000 m^3/d since 1985 whereas in the other regions conventional light capacity increased in 1986 by about 2 000 m^3/d, to 22 000 m^3/d, and has remained relatively steady since then.

The falling productive capacity in Alberta reflects the natural decline in the productivity of the established oil wells. Recently this situation has been exacerbated by the low level of exploration and development following the sharp drop in oil prices in the second half of 1988, and the elimination of government drilling incentives. Actual second quarter crude oil output was only about 125 000 m^3/d, 6 000 m^3/d less than estimated capacity, despite apparent strong demand and no pipeline constraints. This would seem to indicate that other factors may have constrained production and/or that Alberta conventional light crude capacity has been overestimated.

Figure 3.1.1
Conventional Light Crude Oil Productive Capacity
(Second Quarter)
000 m^3/d

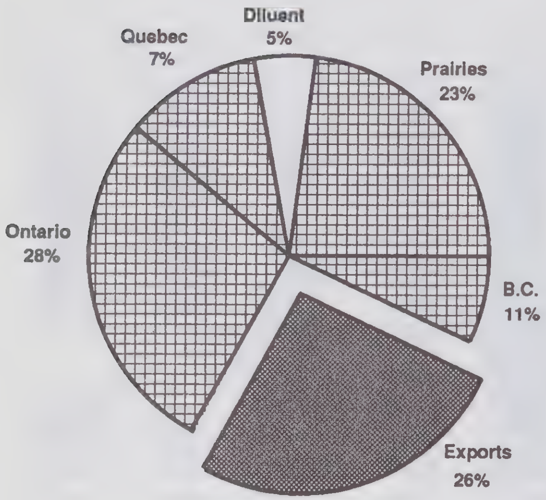


Synthetic crude oil production, averaging over 35 000 m^3/d during the second quarter, was almost 4 000 m^3/d higher than last year. This largely reflected the completion of the Capacity Addition Program (CAP) at Syncrude in the fall of 1988. Condensate supply was up 500 m^3/d, to 17 000 m^3/d.

As outlined in more detail in section 2, second quarter deliveries of domestic crude to Canadian refiners were up compared with last year, despite the decline in production. Exports, however, were down 11% to 47 000 m^3/d.

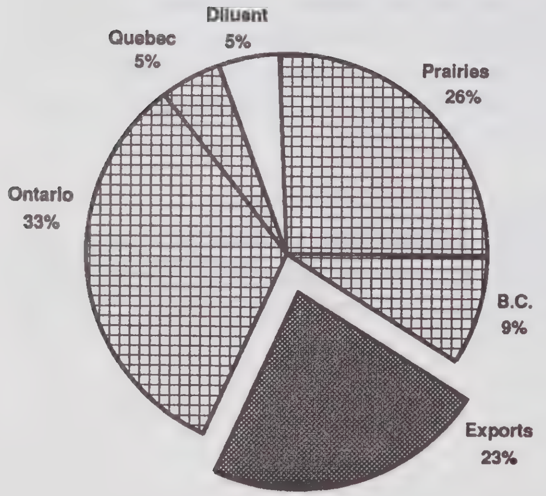
Figure 3.1.2
Light Crude Oil and Equivalent Disposition
(Second Quarter)

1988



203 000 m^3/d

1989



201 000 m^3/d

1989 Outlook

Since April Alberta conventional light crude production has been 5 to 6 000 m^3/d less than expected, despite adequate pipeline capacity, indicating that productive capacity may have been overestimated. As a result, the NEB recently reduced its estimates of supply from Alberta. It lowered its forecast of productive capacity by about 4 000 m^3/d for the remainder of 1989 and the forecast for 1990 is under review. Alberta productive capacity for the third quarter is currently forecast at about 128 000 m^3/d; fourth quarter supply is estimated at 126 500 m^3/d.

Reasons given for the unexpected decline include oil price uncertainty, removal of drilling incentives, a shift to gas exploration, company mergers and lower industry cash flow.

In fact, there is a growing industry consensus that light crude production peaked in the last quarter of 1988 and the long-expected decline in conventional crude capacity may have begun.

As outlined in table 3.1, the current outlook for the year 1989 is for a 3% decline in total production of light crude and equivalent, with production from Alberta expected to decline 5 000 m^3/d, or 4.5%. More than half of the drop is expect to be absorbed in the export market, on the assumption that Canadian refiners will take all their domestic crude nominations.

Table 3.1
Light Crude Oil and Equivalent Production and Disposition
(Annual)
000 m^3/d

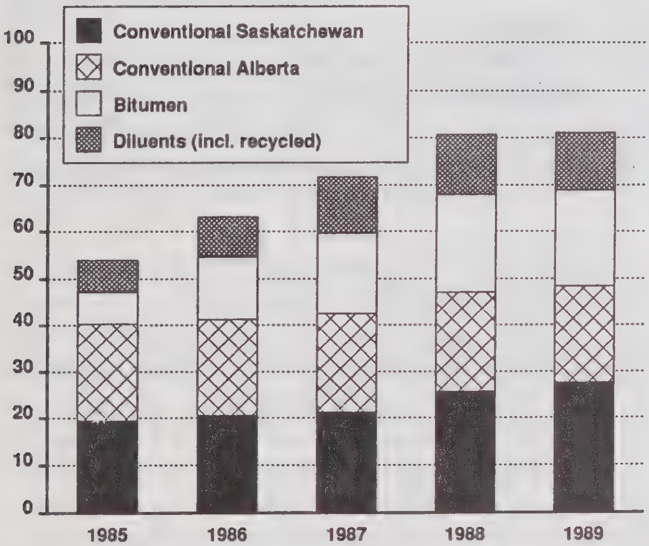
		1988	1989 (E)
I	**Production**		
	Alberta	134	127
	Other Regions	23	23
	Synthetic	32	34
	Pentanes Plus	19	18
		208	202
	Inv. Draw	3	1
	Total Supply	**211**	**203**
II	**Demand**		
	Domestic	149	146
	Export	50	45
	Diluent	12	12
		211	203

3.2 Heavy Crude Oil Supply and Disposition

Total blended heavy crude oil productive capacity during the second quarter of 1989 is estimated to have averaged 81 000 m^3/d, marginally higher than last year. Pentanes plus requirements for blending purposes (including recycled) remained at 13 000 m^3/d. Shut-in of heavy crude capacity averaged about 3 000 m^3/d .

Shut-in during the second quarter can be attributed to several factors. The main cause may have been the overestimation of heavy crude productive capacity. Tougher competition in the United States and the shut-in of higher-cost wells also had an impact.

Figure 3.2.1
Heavy Crude Oil Productive Capacity
(Second Quarter)
000 m^3/d



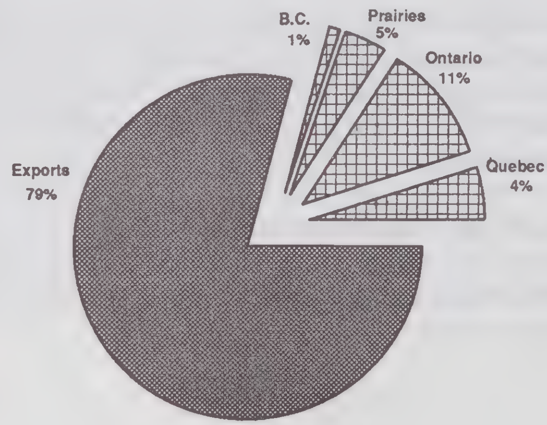
Despite low exploration activity, second-quarter productive capacity of unblended conventional heavy crude oil registered a modest 3% growth, to 48 000 m^3/d. All of this increase was recorded in Alberta, particularly in the Bow River area of the province. Alberta conventional heavy increased by 7%, to 28 000 m^3/d, while capacity in Saskatchewan remained unchanged at about 21 000 m^3/d.

In contrast to the second quarter of 1985 and 1986 when raw bitumen supplies doubled, capacity remained unchanged at about 21 000 m^3/d in 1989 compared with 1988. Low oil prices in the latter half of 1988 slowed or postponed the development of a number of bitumen projects.

With heavy crude demand up substantially (see Section 2) and heavy crude production relatively flat, exports in the second quarter fell by 15% (or 10 000 m^3/d) to 55 000 m^3/d, compared with a year earlier.

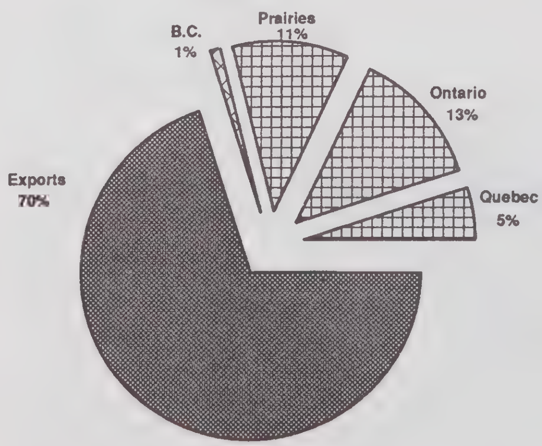
Figure 3.2.2
Heavy Crude Oil Disposition*
(Second Quarter)

1988



83 000 m^3/d

1989



79 000 m^3/d

* *Includes inventory draw of 6 000 and 2 000 m^3/d in 1988 and 1989 respectively*

1989 Outlook

A recent National Energy Board forecast indicates that total blended heavy crude oil production for 1989 may have plateaued at about 80 000 m^3/d. An expected 1% drop in production from last year is the direct result of lower exploration and development activity.

However, total conventional (unblended) heavy crude production is expected to increase marginally on a year-over-year basis, to about 46 000 m^3/d. All of this increase is expected to come from Alberta. This increase, reflecting higher in-fill drilling in 1988, may be short-lived. Second half 1989 conventional production is expected to average 47 000 m^3/d, 2% higher than the same period last year.

Bitumen production is forecast to average 20 000 m^3/d, slightly lower than last year. If crude oil prices improve, various bitumen projects could quickly be brought back on stream. Until then, producers will maintain a "wait and see" attitude.

Given the likelihood of declining to flat supply in conjunction with higher domestic demand, heavy crude exports are forecast to average 56 000 m^3/d, 11% below last year's level.

Table 3.2
Heavy Crude Oil Production and Disposition
(Annual)
000 m^3/d

I	**Production**	**1988**	**1989 (E)**
	Conventional		
	Alberta	23	25
	Other	22	21
	Bitumen	21	20
	Diluent	13	12
		79	79
	Inventory Draw	2	1
	Total Supply	81	80
II	**Demand**		
	Domestic	18	24
	Exports	63	56
		81	80

4. Pipelines

- *Throughput on most pipelines was down in the second quarter because of lower than expected crude output.*

- *According to mid-year forecasts, this trend is expected to continue for the balance of the year.*

4.1 Trans Mountain Pipe Line Throughput

Crude oil and petroleum product shipments via the Trans Mountain Pipe Line (TMPL), at 29 000 m^3/d during the second quarter of 1989, were about 7% lower than the same period a year ago. Although some maintenance work on the pipeline temporarily reduced throughput capacity there was nevertheless sufficient spare capacity over the period to avoid apportionment. About 87% of movements originated from Alberta, with the remainder consisting of crude oil delivered from wells in the interior of British Columbia.

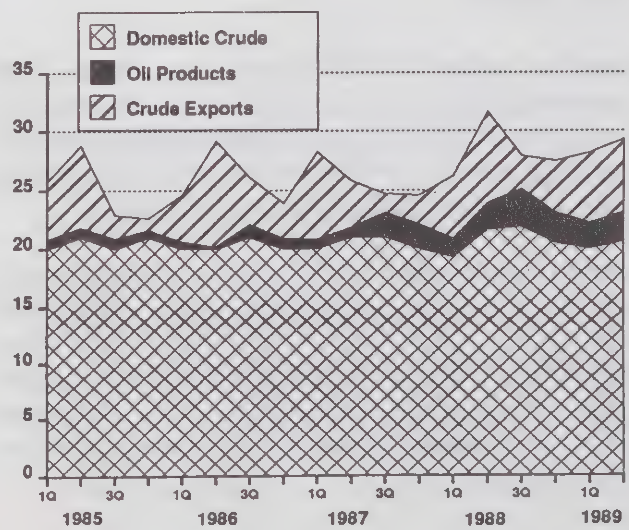
Deliveries to Vancouver area refineries fell 6% to below 21 000 m^3/d, largely reflecting refinery turnarounds which lowered crude run to stills. Faced with strong regional growth in product consumption refiners reduced product exports while maintaining imports.

To take advantage of economies of scale in their refining operations while minimizing environmental concerns in the Vancouver area, the majors have in recent years shifted some of their refining operations from Vancouver to Edmonton. This in turn has resulted in increased deliveries of semi-refined products from Edmonton to Vancouver. As a result of this ongoing process towards greater integration, Vancouver refineries have roughly doubled their receipts of partially processed oil from Edmonton since the fourth quarter of 1988, while concurrently reducing their intake of light crude oil. This was reflected in the changing mix of Trans Mountain deliveries. Approximately 15 000 m^3/d of light crude oil and equivalent were shipped to Vancouver refineries this year versus 19 000 m^3/d last year. Partially offsetting this decline, shipments of semi-refined products were up 3 000 m^3/d to over 5 000 m^3/d. Deliveries of heavy crude oil, on the other hand, remained relatively steady at around 600 m^3/d.

In part, to meet strong product demand in the interior of British Columbia deliveries of refined products from Edmonton to terminals in Kamloops rose by 7% to approach 2 500 m^3/d.

With the declining availability of Canadian crude oil for export, netback economics suggests that exports to more remote markets, with their inherently higher shipping costs, will be the first to suffer, other things being equal. This appears to be borne out by the 50% reduction to 2 500 m^3/d in crude oil delivered for export by tanker at Trans Mountain's Westridge marine terminal. On the other hand, pipeline exports to the relatively nearby Puget Sound refineries in Washington state actually increased by a third to 3 600 m^3/d from last year. The increase resulted from spot sales, primarily of condensate. Traditionally, Washington refiners have relied largely on condensate from Indonesia to meet their requirements. However, in recent months these supplies have, to an extent, been diverted to Asian Pacific markets, thereby opening up export opportunities for Canadian producers. In light of the sporatic nature of these transactions, however, it is difficult to project a continuation of these deliveries beyond the very short term.

Figure 4.1
TMPL Deliveries
000 m^3/d



1989 Outlook

According to a mid-year forecast, throughput over 1989 should average about 28 000 m^3/d, virtually unchanged from last year's level but consistent with the trends that have recently emerged. The credibility of the forecast largely depends on the validity of two assumptions that have been made for the latter half of the year: first, that the higher level of exports to Washington state will be maintained; and second, that IPL will not suffer a capacity shortfall, which might otherwise increase TMPL deliveries, when it undertakes an extensive internal inspection program.

4.2 Interprovincial Pipe Line Deliveries

Total Interprovincial Pipe Line deliveries of crude oil and other hydrocarbons, including petroleum products and natural gas liquids (NGL's), during the second quarter of 1989 averaged 235 000 m^3/d, 2% less than a year earlier. For the most part this decline can be attributed to crude oil production shortfalls and pipeline maintenance and inspection programs limiting system capacity. No apportionment of pipeline space occurred during the second quarter.

As a percentage of total IPL deliveries, heavy crude represented about 30%, unchanged from a year ago. Deliveries of light crude declined slightly to 48%. Synthetic deliveries registered a 6% increase on relatively small volumes.

Sixty two percent of IPL deliveries were destined for Canadian markets with most of the remainder delivered to the United States mid-west. Total domestic deliveries increased by 8%, to 144 000 m^3/d while IPL deliveries to the United States fell by 13% , to 90 000 m^3/d.

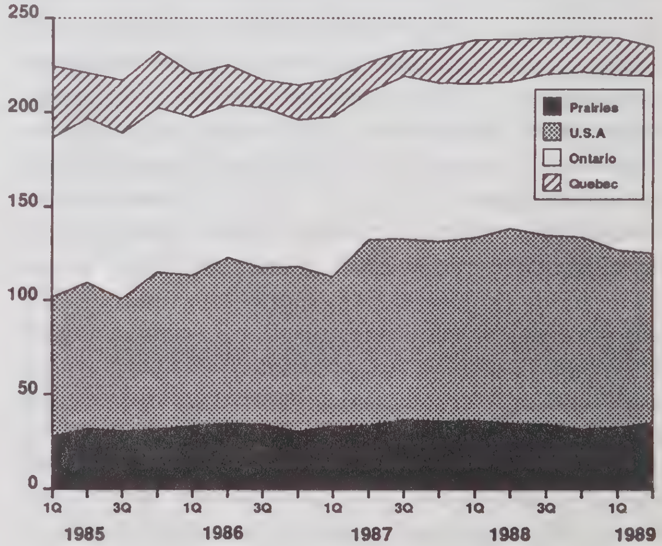
Ontario was the only Canadian market to register a significant increase in deliveries. IPL deliveries averaged 94 000 m^3/d, up 20% from a year ago. This increase not only reflected strong product demand but also higher crude oil throughput compared with last year when refinery turnarounds had a significant impact on feedstock deliveries.

Prairie deliveries, which were somewhat less than expected because of operational problems at the Newgrade upgrader, increased slightly to 35 000 m^3/d. In Quebec, tight domestic crude oil supply and offshore price opportunities reduced deliveries by almost 30%, to 16 000 m^3/d.

For a number of years, IPL has been operating at close to capacity and at times throughput has exceeded the recommended operating margin. Apportionment of pipeline space on the IPL system has become routine with the added risk of reduced throughput due to equipment failure and downtime.

IPL plans to proceed with a 7 000 m^3/d debottlenecking program , subject to industry support and National Energy Board approval. According to IPL, this modest program between Edmonton and Superior,Wisconsin, at an estimated cost of $85 million (1989 $) would remove current bottlenecks and satisfy delivery patterns as defined by current industry production forecasts. IPL considers this smaller capacity expansion project the last upgrade possible without laying an entirely new pipeline.

Figure 4.2
Total IPL Deliveries
000 m^3/d



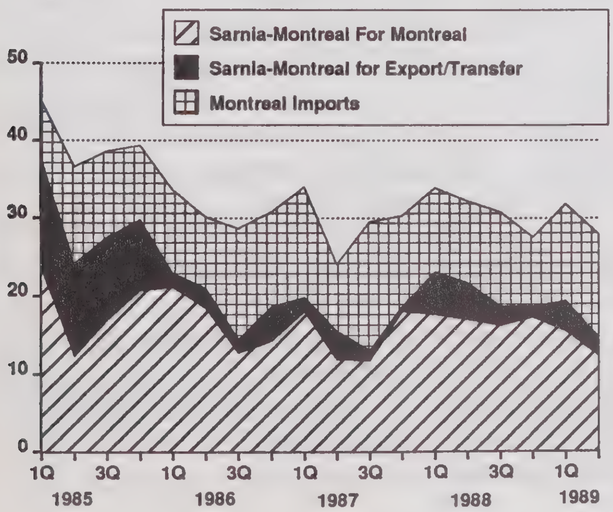
1989 Outlook

The most current IPL delivery forecast, based on current industry information, suggests that 1989 throughput will remain below last year's level. Deliveries this year are expected to average 222 000 m^3/d, 8% less than last year and 2% less than IPL's previous forecast for the year. Much of the forecast decline reflects lower-than-expected crude oil production.

4.3 Pipelines to Montreal

Deliveries of crude oil and equivalent via the Sarnia-Montreal section of the IPL system dropped by close to 30% compared with the second quarter of 1988 and, at 15 500 m^3/d, were at the lowest level since the third quarter of 1987. The decline was split equally between the domestic and export markets. Several factors contributed to the decline. Refiners shifted to the import option as Canadian light crude was at a disadvantage to theoretical Brent imports, (in contrast to the "usual"relationship) particularly in the latter half of the quarter (see section 7 on prices). In addition, light conventional Canadian crude oil production was less than expected causing both Ontario and Quebec refiners to increase crude imports. Imports through the Portland Pipeline system were up almost 2 000 m^3/d, to 12 500 m^3/d, offsetting much of the drop in domestic deliveries to Montreal refiners.

Figure 4.3
Crude Oil Deliveries to Montreal
000 m^3/d



On the "export" side, exports and domestic transfers fell more than 60%, to 2 300 m^3/d as a result of increased domestic heavy crude demand and little or no growth in heavy crude production (see section 3).

1989 Outlook

Despite the fall-off in second quarter throughput, IPL is forecasting second half deliveries to exceed last year's level. For the year 1989 deliveries are expected to average 20 000 m^3/d, slightly less than in 1988, but still about 20% higher than in 1987.

IPL deliveries to Montreal refiners are forecast to account for 80% of 1989 throughput, with exports and domestic transshipments accounting for the balance.

Crude oil imports by Montreal refiners are forecast to be up slightly in 1989 compared with 1988. In total, refinery feedstock requirements should be basically unchanged in 1989.

Table 4.3
Deliveries to Montreal of Crude Oil and Equivalent
(Annual)
000 m^3/d

	1987	1988	1989 (E)
I Sarnia-Montreal Pipeline	17	21	20
i) To Montreal Refiners	15	17	17
ii) For Export/Transfer	2	4	3
II Crude Oil Imports	13	11	11

5. Exports and Imports

- *Crude oil exports continue to decline in 1989 reflecting lower output and greater domestic demand.*

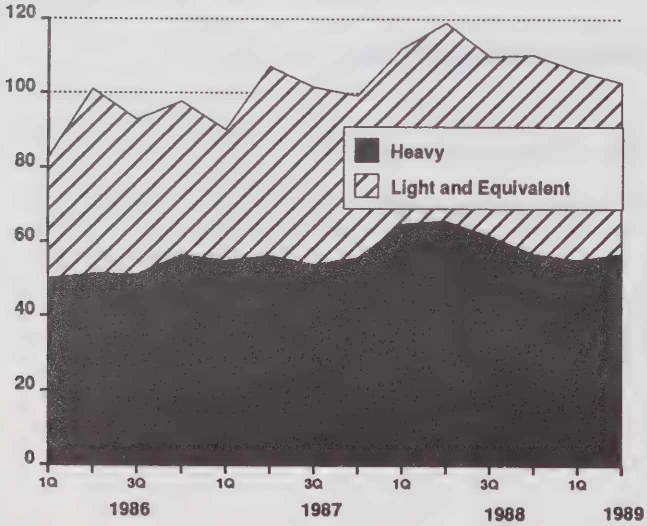
- *In contrast, imports of both crude and products are higher than in the same period last year.*

5.1 Crude Oil Exports

In the second quarter and for the second successive quarter, crude oil and equivalent exports declined on a year- over- year basis. In fact, exports have been declining since they peaked in the second quarter of 1988. Falling production and increased Canadian demand for heavy crude have been the main factors contributing to the slide in exports.

Total exports dropped 15 000 m^3/d, or 13%, to 104 000 m^3/d compared with the second quarter of 1988. Heavy crude exports fell 16% to 57 000 m^3/d as production remained flat and Canadian refiner demand was up. In contrast to the first quarter, light crude and equivalent exports also were lower, declining 12% to 46 000 m^3/d, reflecting the drop in light crude production. In addition more light crude had been available for export in the second quarter of 1988 because some refineries in the Prairies and Ontario were on extended or partial shutdowns for maintenance.

Figure 5.1.1
Crude Oil Exports
000 m^3/d



The level of net crude oil exports has also declined in line with the slide in crude exports. Exports exceeded imports by more than 50 000 m^3/d in the second quarter of 1988. By the second quarter of 1989 the difference was only 30 000 m^3/d.

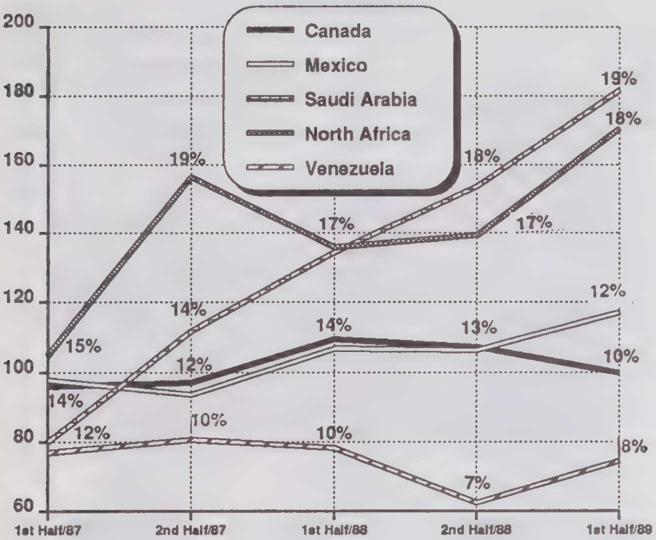
Table 5.1.
Crude Oil Exports by Destination
(Second Quarter)
(000 m^3/d)

	Light		Heavy		Total	
	1988	1989	1988	1989	1988	1989
United States PAD Districts						
I	7	8	3	1	10	9
II	33	27	55	47	88	74
III	-	-	2	3	2	3
IV	8	8	4	3	12	11
V	3	4	1	1	4	5
Total U.S.	51	47	65	55	116	102
Offshore	1	-	2	2	3	2
Total	52	47	67	57	119	104

As might be expected, much of the decline in exports occurred in the PADD II Twin Cities and Chicago markets. Total exports into these two markets were down more than 14 000m^3/d, to 60 000 m^3/d. Only exports to PADD III and V were higher. Exports were up 25% or 1 000 m^3/d in PADD V. As discussed in section 3 most crude movements into PADD V are to refiners in the state of Washington. The additional purchases reflected spot purchases of Canadian condensate.

While Canadian exports to the United States have been declining since the first half of 1988, total U.S. crude oil imports have continued to rise, in particular light crude, as U.S. product demand remains high and domestic production declines. U.S. crude oil imports have jumped 40% in the last two years, reaching 950 000 m^3/d in the first half of 1989.

Figure 5.1.2
U.S. Crude Oil Imports and Market Share
000 m^3/d



As illustrated in figure 5.1.2, the Canadian share of the U.S. crude import market remained about 13% throughout 1987 and 1988. Canadian exports grew at roughly the same rate as overall U.S. imports. In the first half of 1989, however, the Canadian market share fell to 10%, commensurate with the drop in Canadian exports. It appears the OPEC countries have replaced the lost Canadian crude.

Figure 5.1.3
Crude Oil Imports and Market Share
PADD II
000 m^3/d

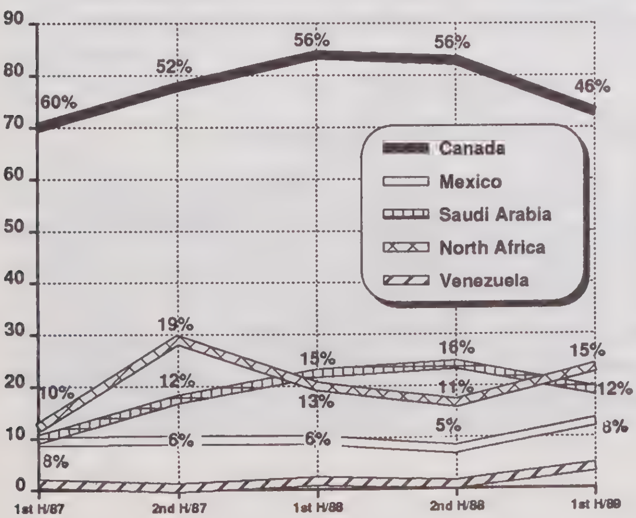


Figure 5.1.3 illustrates the importance of Canadian crude to PADD II refiners. The regional trend over the last two years has been no different than the national trend. In 1987 and 1988 Canada accounted for 55% of the 140 000 m^3/d of crude oil imports into PADD II. By the first half of 1989 the Canadian share had dropped to 45%.

1989 Outlook

The outlook for crude exports in the second half of 1989 is for "more of the same". Conventional light crude supply is forecast to be 7 000 m^3/d lower in the second half. Canadian demand for light crude is programmed by refiners to drop 3 000 m^3/d. Assuming no shut-in or inventory change and that Canadian refiner nominations will be met first, light crude exports should average about 6 000 m^3/d less, at 44 000 m^3/d, in the second half of 1989 compared with the second half of 1988.

With respect to heavy crude, second-half exports are estimated to fall 5 000 m^3/d, to 56 000 m^3/d, based on a forecast of slightly lower production coupled with substantially higher Canadian refiner demand.

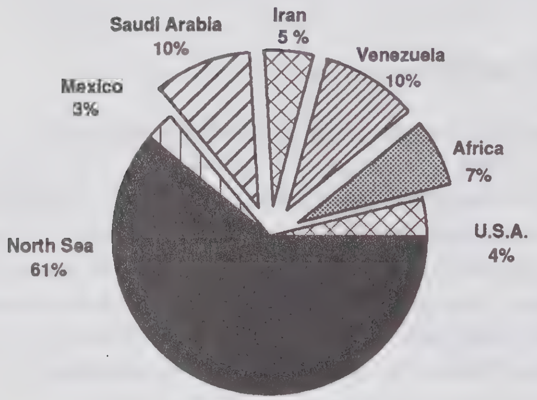
5.2 Crude Oil Imports

During the second quarter of 1989 total crude oil imports averaged 76 000 m^3/d, up 13% (9 000 m^3/d) from the same period in 1988.

OPEC's share of foreign supply increased by 4 percentage points to 37%, reflecting a volumetric increase of 6 000 m^3/d to 28 000 m^3/d. The largest increase was in African imports which more than doubled. North Sea crude accounted for 56% of all foreign crude receipts (4 percentage points less than a year ago). Imports from the U.S. increased by 60%, to 4 000 m^3/d, while those from Mexico dropped by half to 1 000 m^3/d.

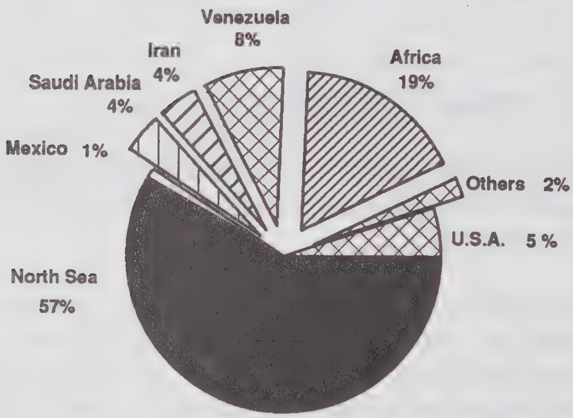
Figure 5.2.1
Sources of Crude Oil Imports
(Second Quarter)

1988



67 000 m³/d

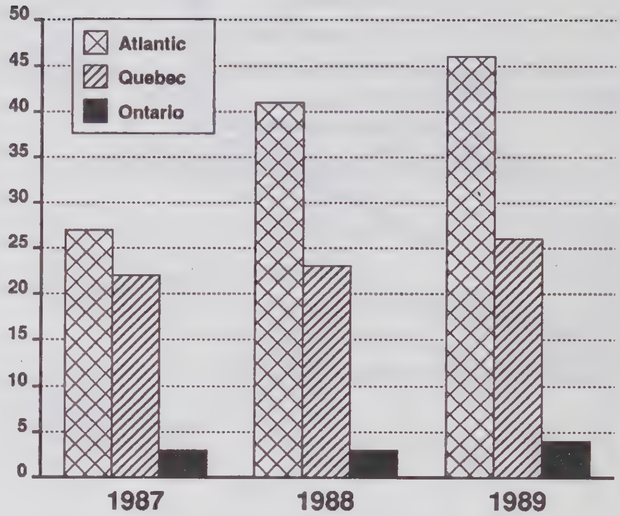
1989



76 000 m³/d

Ontario imports at 4 000 m³/d, were 56% higher at while in the Atlantic and Quebec they were 11% higher. In part, the increases in Quebec and Ontario reflected offshore crude price opportunities and the unexpected decline in Canadian light crude production.

Figure 5.2.2
Crude Oil Imports by Region
(Second Quarter)
000 m³/d



1989 Outlook

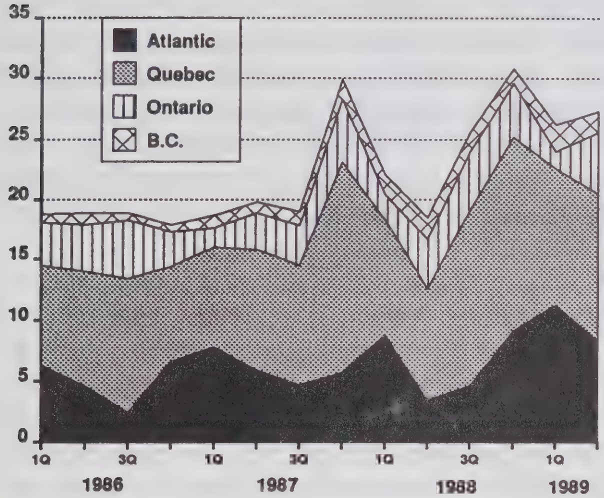
According to refiners' expectations, imports during the second half of the year are estimated to be unchanged from the second half of 1988. For the year in total, imports are forecast at 74 000 m³/d, up 2 000 m³/d from 1988. Higher receipts are forecast by Atlantic and Ontario refiners while in Quebec imports will decline.

With respect to crude sources, no significant changes are expected. The North Sea will account for 60% of total imports; however, imports from the United States (to Ontario) and OPEC countries should increase slightly.

5.3 Petroleum Products

Over the last year petroleum product imports have risen significantly. Since the second quarter of 1988 imports have averaged about 27 000 m³/d, almost 50% higher than in 1986 and 1987. A world wide reduction in petroleum product trade barriers, excess refining capacity and lower prices have all contributed to the general rise in product imports.

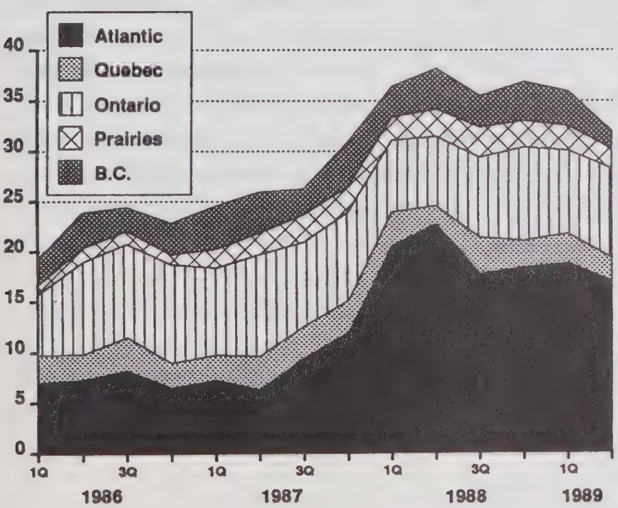
Figure 5.3.1
Petroleum Product Imports
000 m³/d



About two-thirds of the increase has occurred in the Quebec market. The Atlantic region accounted for the other third.

In Quebec, imports of transportation fuels such as jet fuel and motor gasoline are higher; however, the bulk of the increase has been in the heavy fuel category, reflecting strong growth in industrial consumption and the need for thermal electricity generation.

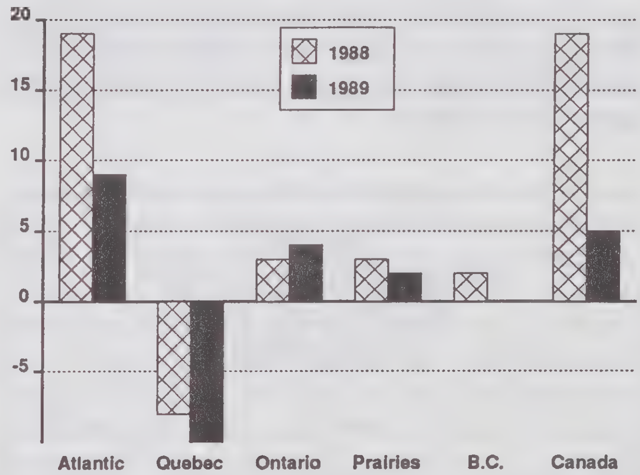
Figure 5.3.2
Petroleum Product Exports
000 m³/d



With respect to petroleum product exports, in the past five years the only change of note was in late 1987/early 1988 when exports jumped 75%, or about 15 000 m³/d with the reactivation of the Come-By-Chance refinery.

In the second quarter of 1989 exports were about 32 000 m³/d, 6 000 m³/d less than in the second quarter of 1988. All of the decline occurred in the Atlantic and British Columbia.

Figure 5.3.3
Net Petroleum Product Trade
(Second Quarter)
000 m³/d



With the increase in product imports over the last year and little change in export levels, (except for the most recent quarter) the net petroleum product trade surplus has been reduced by approximately half, to average 9 000 m³/d during the last year. The second-quarter surplus deteriorated further, to 5 000 m³/d, as a result of the drop in exports.

6. Energy Trade

- *The Canadian energy trade surplus declined by 30% on a year-over-year basis in the second quarter.*

- *Lower exports and higher imports of crude oil and refined products were the main reasons for the decline.*

6.1 International

On a customs basis, Canada recorded a trade deficit of over $300 million in its merchandise (visible goods) account in the second quarter of 1989. Nevertheless, it continued to enjoy a surplus in the energy trade component of this account. In keeping with the established pattern, this was accomplished by running up a larger energy trade surplus with the United States than the deficit it incurred with other countries. The United States accounted for 85% of Canadian energy exports but only 30% of imports. The total value of energy exports surpassed $3.2 billion during the second quarter against imports of $1.7 billion.

Table 6.1
Canadian Energy Trade *
Second Quarter 1989
$ CAN (millions)

	Exports	Imports	Balance
Crude Oil	1250	980	270
Petroleum Products	475	415	60
Natural Gas	695	-	695
LPGs	120	40	80
Coal and Products	465	250	215
Electricity	175	40	135
Uranium	70	10	60
TOTAL ENERGY	**3250**	**1735**	**1535**

* *figures are rounded*

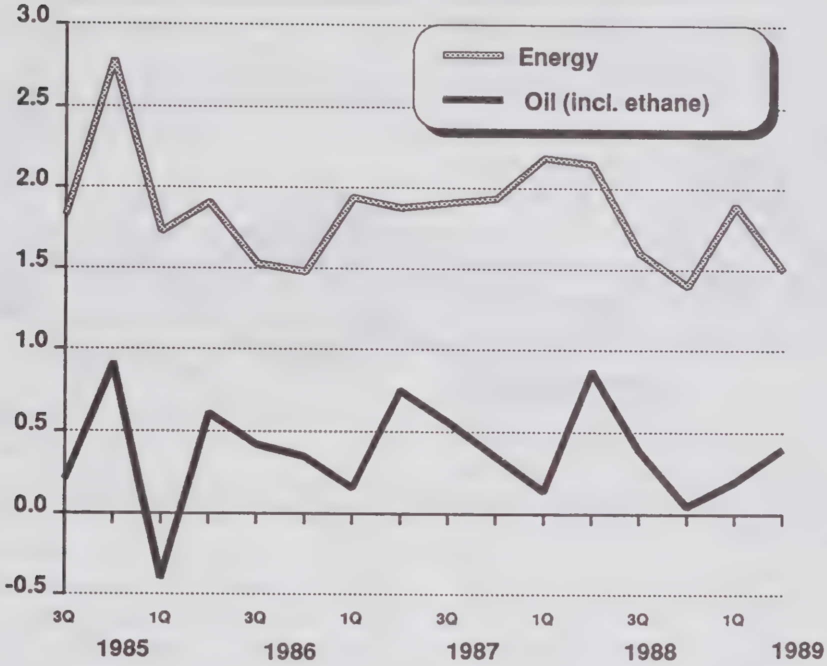
The $1.5 billion surplus was nevertheless substantially below that recorded for the same quarter last year, when it approached $2.1 billion. The decline was essentially import-driven, as exports were reduced by only $100 million whereas imports were almost $500 million higher. About 80% of the net decline was attributable to the falling trade surpluses in the crude oil and petroleum product accounts. This might be expected since crude oil and products together typically account for almost half of all energy exports and over four-fifths of imports.

In part, the decline in the energy trade surplus reflected stronger domestic demand as well as the appreciation of the Canadian currency against other currencies. In the case of crude oil and products in particular, it appears also to have resulted from supply constraints on crude oil exports. As a result of declining domestic crude oil supply, and higher refined product demand in Canada, the availability of crude oil for export was reduced. Although crude export netback prices were more than 20% higher this year than last, export volumes actually declined by 15%. At the same time domestic refiners lowered product exports and increased imports of both crude oil and products. This process narrowed the gap between the values of imports and exports.

Declining trade surpluses were also recorded for electricity and liquefied petroleum gases where, in a similar fashion, exports were down and imports up; and for uranium, where both exports, and to a lesser extent, imports were down. Trade in these commodities was by and large with the United States.

On the other hand, the combined coal and products surplus remained relatively steady, reflecting little change in either the value of exports or imports from last year. About 90% of all coal-related exports were destined for offshore; a similar percentage of imports came from the United States. Finally, the natural gas surplus grew commensurately with the value of exports as virtually no natural gas is imported into Canada.

Figure 6.1
Oil and Energy Trade Balance
$ CAN (Billions)



6.2 United States

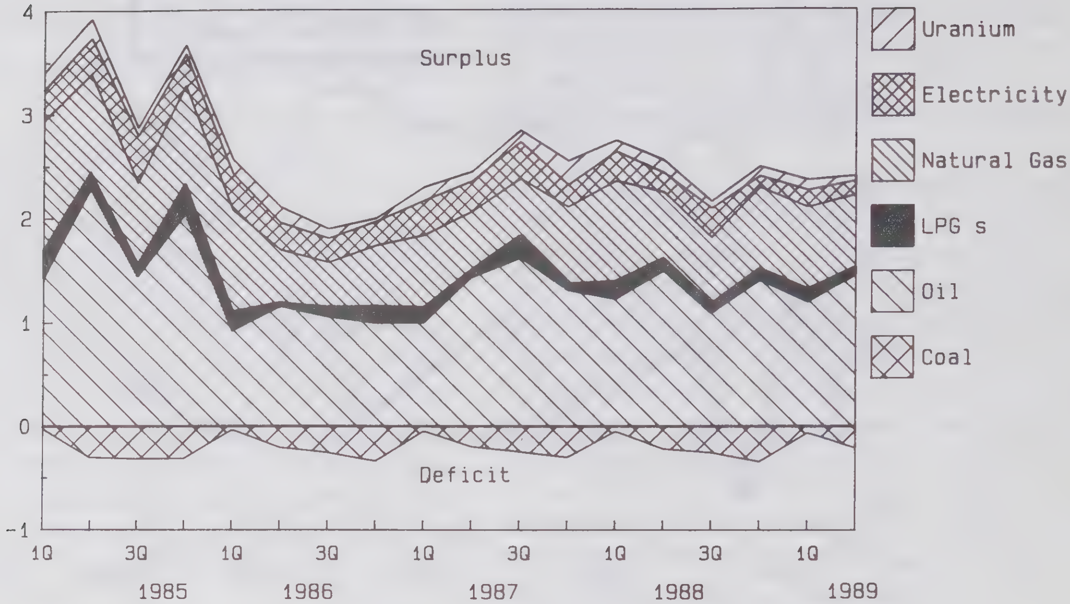
As indicated above, well over three quarters of Canadian energy exports are destined for the United States. These exports amounted to some $2.7 billion in the second quarter, or about five times the value of corresponding imports from the United States. Canada's energy trade surplus with the United States, on a customs basis, therefore netted out to about $2.2 billion during the quarter. This represented a modest deterioration (7%) in the surplus from last year.

While the value of crude oil exports was up by 8%, this was entirely due to substantially higher export prices as export volumes declined significantly (see section 5). As previously discussed, this volumetric decline largely reflected the fall off in Canadian crude oil supply against a backdrop of unfavorable exchange rate movements and strong domestic demand. The fact that U.S. demand for refined petroleum products remained virtually flat throughout the first half of 1989 also played a part in curtailing crude and product exports in the second quarter.

In contrast to oil, Canada has, at current prices, abundant supplies of natural gas. By pursuing aggressive pricing strategies and by taking advantage of the deregulated natural gas market in the United States, Canadian suppliers continue to make inroads into the U.S. market. This was reflected in the 10% increase, on a year-over-year basis, of the natural gas trade surplus in the second quarter. Moreover, unlike oil, the surplus was essentially a product of higher export volumes as prices rose only marginally. This suggests that U.S. demand for Canadian gas may have been spurred by the comparative price advantage natural gas now offered, relative to oil, in fuel-switchable markets.

As a result of low water levels and strong domestic demand in Canada, exports of electricity fell while imports from the United States increased during the second quarter, leaving a smaller surplus relative to last year. Similarly, the trade surpluses associated with liquefied petroleum gas and uranium also suffered declines. On the other hand, the traditional trade deficit with the United States in coal and related products was maintained at last year's level.

Figure 6.2
Net Energy Commodity Trade with the U.S. (Value)
$ CAN (Billions)



7. Crude Oil and Product Prices

- *The price differential between WTI and Brent widened considerably in the second quarter, reflecting market developments in the United States.*
- *Canadian gasoline prices continued to rise as a result of both tax and crude cost increases.*
- *An historical review of Canadian and American gasoline markets highlights a number of factors contributing to different prices in the two countries.*

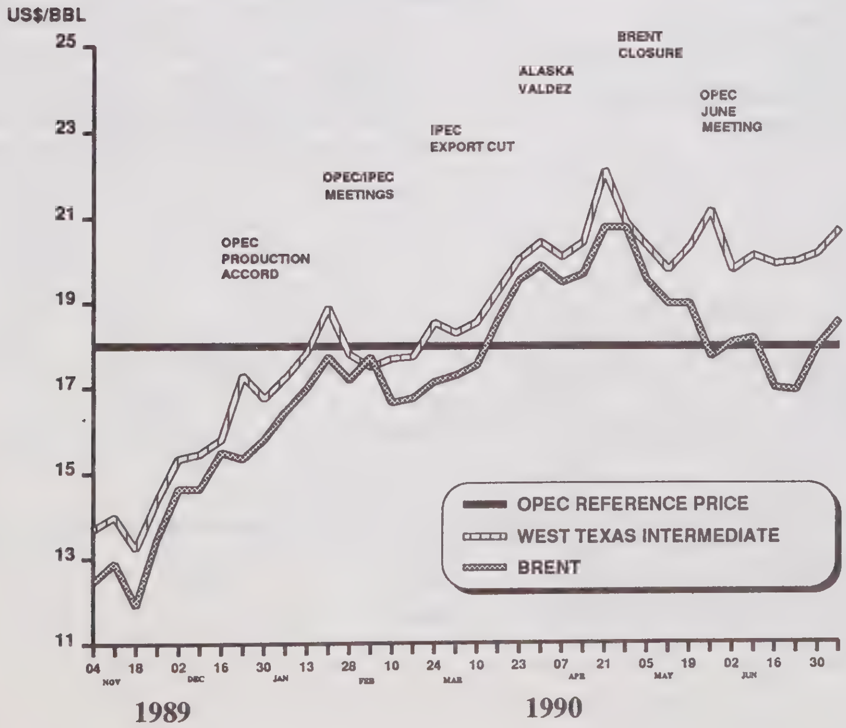
7.1 International Crude Oil Prices

After the surprising strength displayed by oil markets in the first quarter of 1989, crude oil prices retained their upward trend entering the second quarter, with West Texas Intermediate (WTI) averaging almost $21/bbl in April. This was $7.25/bbl higher than the low October 1988 price of $13.75/bbl. The main factor contributing to this sharp increase was the mid-April explosion on the Brent system's North Sea Cormorant Alpha platform, which shut down the system for several weeks. This compounded production difficulties experienced in the North Sea since the Piper Alpha disaster in July, 1988. With concerns over light crude availability and the onset of what was expected to be a high demand motor gasoline season, crude oil prices increased sharply.

Prices began to fall slightly in May, however, averaging $20.50/bbl (WTI), as OPEC production continued to increase. Earlier in the month fears of serious non-OPEC supply difficulties had eased as Alaskan production returned to normal and plans for reopening the Brent system by end-May were announced.

Although a number of OPEC members were producing well above quota prior to the June OPEC meeting, there were a number of other factors that were working to keep crude oil prices buoyant. The International Energy Agency (IEA) had revised its supply/demand estimates for the non-Communist world and these revisions indicated that world oil demand had significantly outpaced world oil supply. Nevertheless, the June average price for WTI fell to just under $20/bbl. This weaker market

Figure 7.1.1
Crude Oil Prices
$ US/bbl



resulted from the OPEC decision to raise its output ceiling and uncertainty as to whether or not Kuwait and the UAE would keep to their quotas.

Despite the erosion in prices over May and June, WTI averaged $20.50/bbl over the second quarter, while Brent averaged $18.60/bbl.

7.2 WTI/Brent Differential

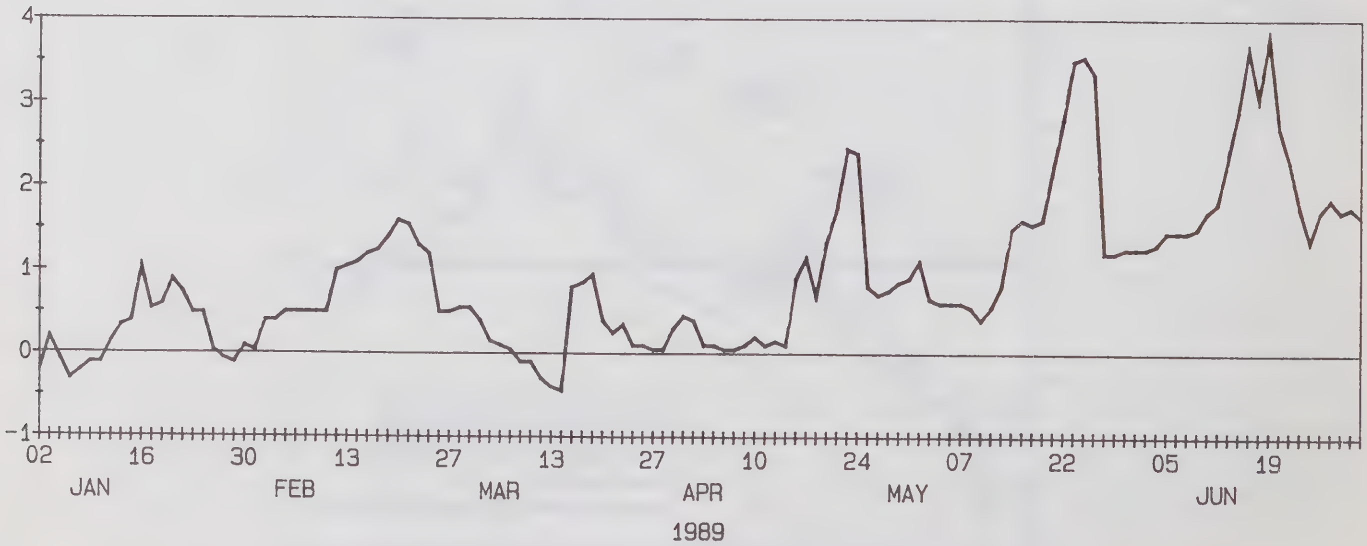
From 1983 to 1986, on an annual average basis, the crude oil price differential between WTI and Brent at the U.S. Gulf Coast was virtually at parity. Nevertheless, from time-to- time disparities of up to $2/bbl or more did prevail, reflecting the powerful influences of local market conditions (e.g. high gasoline demand in the U.S. or high heating fuel demand in Europe).

Since 1986, the U.S. local market conditions have played a larger role as domestic crude oil production has declined by 900 MB/D (most of which has been WTI-type crude). This has heavily impacted on midwestern U.S. refineries which process largely domestic crude oil to meet rising motor gasoline requirements. With only one pipeline (ARCO's) capable of moving limited volumes of imported crude into the region (about 80 MB/D), there is now sharp competition among refiners for incremental barrels of WTI.

As illustrated in Figure 7.2.1, the price differential widened further in the second quarter of 1989, reaching $3/bbl in May and June. The continued decline in U.S. light crude production, foreign crude logistics and an oversupplied local market for Brent crude all contributed to widening the gap.

Higher gasoline prices over the second quarter also allowed local refiners to pay a premium for WTI. Motor gasoline prices were higher in the mid-continent, relative to other markets, because gasoline production in the region was constrained. Refineries in Oklahoma, Kansas and Missouri were operating at or near peak capacity in the second quarter (API data indicated that during the first week of July refineries in this region operated at 100.1% of capacity). In these states the Reid Vapour Pressure Standard was also reduced to the federal standard further inhibiting gasoline production. The facilities to move additional volumes of product into this region are not available.

Figure 7.2.1
WTI/Brent Price Differential
$ US/bbl



The price of WTI and the price differential to Brent impact directly on Canadian crude prices and the marketing of domestic crude. Since Canadian light crude prices track WTI prices, Canadian prices also rose relative to Brent and other international light crudes. As a result, domestic light crude at Montreal was at a disadvantage to imports (in contrast to the "normal" situation), particularly in May and June, thus providing an incentive for Quebec refiners to increase the import mix of their crude slate.

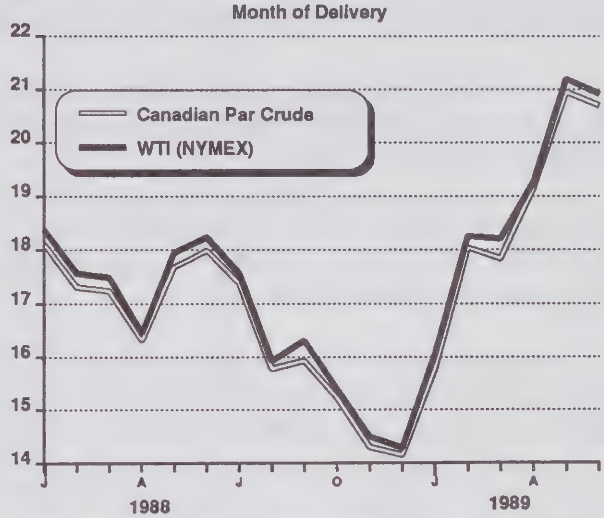
By August, however, the WTI/Brent differential had narrowed to more historical levels and the Brent price advantage to Canadian light at Montreal had disappeared.

7.3 Domestic Crude Oil Prices

During the second quarter 1989, light Canadian crude oil posted prices averaged $23.32 per barrel, an increase of $2.77 from first quarter 1989 prices. The increase is attributed to an international oil price increase of about US$2.30 per barrel (equivalent to about Cdn$2.75 per barrel).

Canadian light crude oil prices follow the trend set by international crudes, primarily the U.S. benchmark crude West Texas Intermediate (WTI). The following graph illustrates the close relationship between prices for WTI and Canadian crude, after adjustments for delivery times to Chicago. The differential between those crudes, in Chicago, decreased from about US$0.29 per barrel during the first quarter 1989 to US$0.19 during the second quarter 1989.

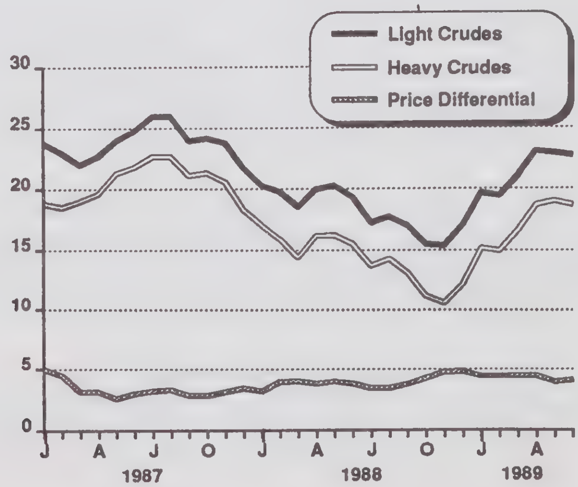
Figure 7.3.1
Canadian Par Crude vs WTI (NYMEX)*
$US/bbl



** New York Mercantile Exchange*

The graph below compares actual prices for Alberta light and heavy crude oil, purchased for use in Canada at main trunk line injection stations. On average, reported light conventional crude oil quality during the second quarter 1989 was 37.6° API, 0.38 % sulphur and blends of heavy crude were 24.3° API, 2.56 % sulphur.

Figure 7.3.2
Comparison of
Domestic Light and Heavy Crude
Actual Purchase Prices - Alberta
$CDN/bbl



New Quality Differentials for Canadian Crudes

The differential between Canadian light and heavy crude prices, during the second quarter, was about $4.19 per barrel, $0.26 lower than the first quarter differential.

Effective June 1, 1989 the oil industry revised the quality adjustment scales* used for pricing crude oil. Light crude prices were affected the most.

Narrowing the density differential and introducing a sulphur credit enables most producers of light crude to receive relatively higher prices.

** For light crude oil (density = 825 to 875 kg/m^3), the density adjustment was reduced from $0.19/kg/m^3 to $0.16/kg/m^3 and a sulphur credit of $0.15/g/kg was introduced for crudes with a sulphur content of less than 5.0 g/kg. For light crudes exceeding a sulphur content of 5.0 g/kg, the penalty remains at $0.30/g/kg.*

7.4 Petroleum Product Prices

7.4.1 Price Trends

The average Canadian price for regular unleaded gasoline at self-serve outlets increased by 3.6 cents per litre, or 7%, during the second quarter of 1989 (June 27 vs March 28). However, gasoline tax and crude cost increases of 1.9 and 2.4 cents per litre, respectively, were not fully recovered by the higher average retail price.

Price increases, which were reported in each of the ten cities, ranged from 1.6 cents per litre in Toronto to 10.6 cents per litre in Regina. The large Regina increase reflected the end of a price war during the quarter, a market situation also prevalent in other Prairie cities during the period.

Retail diesel prices, on a Canada average basis, increased only 0.5 cents per litre during the second quarter. Increases of 0.6 cents during April and 0.2 cents per litre during May were partially offset by declining prices in June. The most notable change was a price decline of 5.4 cents per litre in Saint John, N.B., due to price war activity which began in early June. Other changes in the remaining cities ranged from a 0.7 cent per litre decrease in Toronto to a 3.6 cent per litre increase in Regina.

Table 7.4
Average Regular Unleaded Gasoline Prices
Self-Serve
1988-1989

	1988			1989		%
	June 28	Sept 27	Dec. 27	March 28	June 27	Change 12 mo.
	cents per litre					
St. John's(NFLD)	53.9	52.5	50.9	52.2	56.3	4.5
Charlottetown	52.3	50.9	49.6	49.6	51.5	-1.5
Halifax *	50.9	49.5	47.9	48.8	52.4	2.9
Saint John(N.B.)*	50.7	49.8	48.6	50.2	53.3	5.1
Montreal	57.1	55.8	54.0	55.0	58.1	1.8
Toronto	48.6	46.5	45.9	48.5	50.1	3.1
Winnipeg	42.1	45.9	44.5	43.9	50.9	20.9
Regina	45.6	45.6	39.2	43.3	53.9	18.2
Calgary	41.1	41.6	37.0	41.4	48.2	17.3
Vancouver	48.8	48.8	47.3	49.5	53.6	9.8
Canadian Average	50.1	49.3	47.6	49.5	53.1	6.0
Consumption taxes included:						
Federal	9.9	9.9	9.9	9.8	11.1	12.1
Provincial	9.8	9.9	9.8	9.8	10.4	6.1

* *Full-serve*

7.4.2 Consumption Taxes on Petroleum Products

During the second quarter, combined federal and provincial taxes reflected the largest quarter-over-quarter increase of the 1980s. On an all-grade gasoline basis, federal taxes increased 1.6 cents per litre and provincial taxes were up 0.6 cents per litre (see Appendix V).

The federal government tabled a budget on April 26 which called for changes to both the excise and sales taxes. Effective April 28, the excise tax on gasoline was increased 1 cent per litre and a surcharge of 1 cent per litre was imposed on leaded gasoline to discourage misfuelling. The excise tax on gasoline will be increased a further cent per litre on January 1, 1990. The excise tax on diesel was not changed.

The sales tax rate was increased from 12% to 13.5%, effective June 1, 1989. This resulted in an increase of about 0.4 cents per litre on gasoline and 0.3 cents per litre on diesel. Coupled with the quarterly adjustment on April 1 (a 0.1 cent per litre decrease for both gasoline and diesel), the net sales tax increase was about 0.3 cents per litre on gasoline and 0.2 cents per litre on diesel during the second quarter. The federal sales tax on gasoline and diesel continues to be reviewed quarterly and adjusted according to the Industrial Product Price Index.

Petroleum product tax changes were made in seven of the provinces and in the Northwest Territories between March 1 and June 1. In three of the provinces, the changes resulted from budgets tabled during the quarter.

The May 17 Ontario budget increased the taxes on gasoline and diesel by 1 cent per litre, effective May 18, and an additional cent per litre on January 1, 1990.

On March 30, 1989, New Brunswick and Saskatchewan tabled budgets which changed taxes on some petroleum products. Effective March 31, New Brunswick levied a 2.2 cent per litre surcharge on regular leaded gasoline and Saskatchewan increased its tax on gasoline and diesel by 3 cents per litre and imposed a surcharge of 2 cents per litre on leaded gasoline.

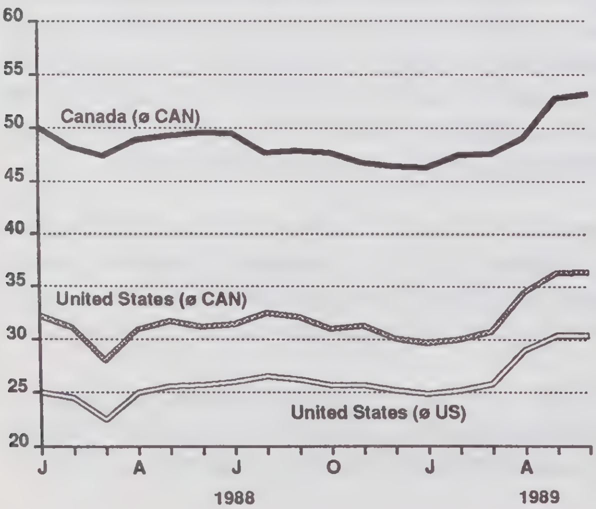
New Brunswick and Saskatchewan are the fourth and fifth provinces, joining Ontario, Manitoba and British Columbia, to implement a higher tax on leaded gasolines as compared to the unleaded grades.

The regular review processes in Newfoundland, Prince Edward Island, Nova Scotia, British Columbia and Northwest Territories resulted in gasoline and diesel tax changes ranging from -0.3 to +0.9 cents per litre.

7.4.3 Canada vs United States

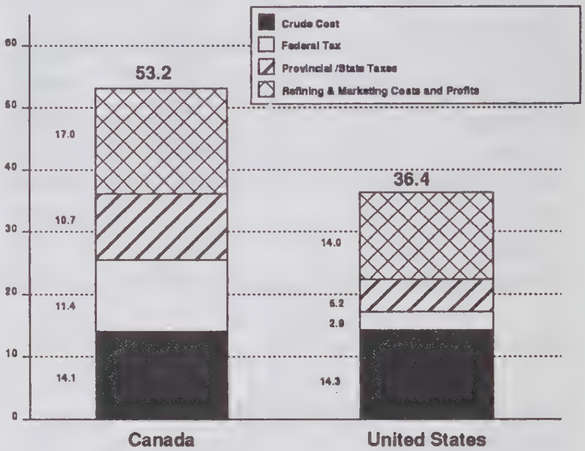
The average retail price for all grades of motor gasoline increased 5.6 cents per litre in both Canada and the United States during the second quarter of 1989. In each of the countries crude costs were up 2.3 cents per litre. Higher refining costs and profits in the U.S. and increased taxes in Canada accounted for most of the balance of the increases.

Figure 7.4.3.1
Average Retail Price of Motor Gasoline
Canada vs United States
cents per litre



In June 1989 the difference between Canadian and American average gasoline prices was 16.8 cents per litre. Higher consumption taxes in Canada account for more than two-thirds of the differential. The balance is attributable to higher refining and marketing costs and/or profits in Canada.

Figure 7.4.3.2
Breakdown of Average Pump Price
(June 1989)
cents CAN /litre



7.4.4 Canada vs United States - Historical Review

The Canadian Oil Markets and Trade Division has recently completed a study entitled "*A Review of Gasoline Retailing Canada vs United States 1973 - 1987*" *. A brief introduction to the report and a summary of its conclusions follow.

Introduction

In recent years, the relationship between retail gasoline prices in Canada and the United States has been the focal point of considerable public attention. Gasoline retailing is one of the most dynamic sectors of the refining and marketing industry. Although the Canadian and American markets are often subject to similar pressures, there are significant differences between the two markets which account for much of the price disparity. The report quantifies some of these differences.

** To obtain copies of the complete report call (613)992-1477 or (613)992-0602.*

In the sections on economies of scale and market structures, the report compares market size and overall product demand in the two countries. The U.S. market is much larger; consequently, efficiencies and economies of scale tend to favour American marketers. The report examines the retail gasoline outlet population, the average gasoline throughput per outlet, the demand for gasoline, the mix of products produced and gasoline quality requirements in the two countries.

Gasoline marketers are constantly adapting their business strategies to the changing conditions in the marketplace, particularly shifts in consumer needs and preferences. The report discusses two retailing innovations: convenience stores (C-stores) and self-serve outlets. It also compares the differences between the Canadian and American experiences with each.

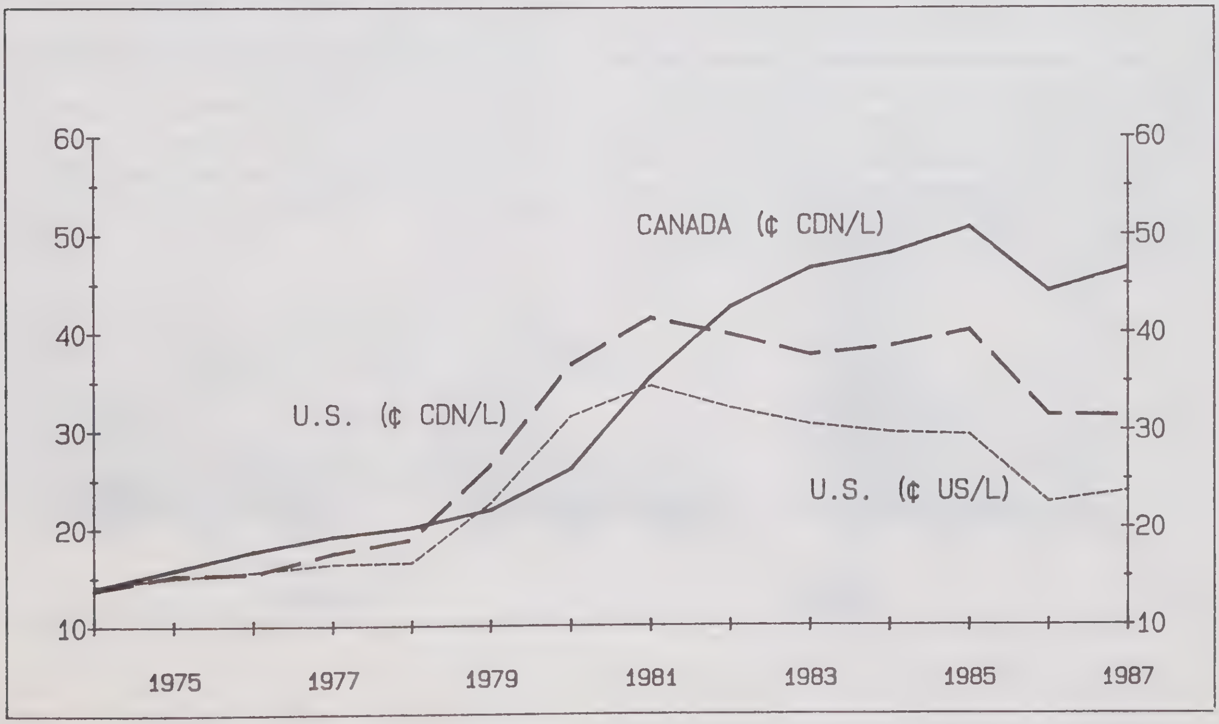
The study also includes a historical perspective of retail prices in Canada and the United States. In the realm of gasoline pricing there are a number of factors influencing retail prices which differ significantly between the two countries. These factors include consumption taxes, price differentials and the mix of gasoline grades sold in each country.

The report focuses on the 1973-1987 period with some pricing coverage extended to include 1988 and the first quarter of 1989.

Summary

Although Canadian gasoline prices are currently substantially above those in the U.S., this was not always the case. Figure 7.4.4.1, which tracks regular leaded gasoline prices from 1973 to 1987, indicates that Canadian and American prices were similar in the 1974-78 period. In the years following the 1979 oil crisis, prices escalated much more rapidly in the U.S. than in Canada. It wasn't until 1982 that Canadian gasoline prices significantly exceeded those in the U.S. The graph also illustrates that had the Canadian dollar not weakened relative to the American dollar, the price differential, in ¢Can/litre, would have been greater than it was throughout most of the period since 1982.

Figure 7.4.4.1
Regular Leaded Gasoline Prices
(Canada vs U.S. Including Tax)
cents / litre



Gasoline markets in both Canada and the United States were subject to varying degrees of government regulation during the 1973-87 period. The U.S. market was deregulated in 1981, while in Canada product prices continued to be influenced by regulated crude oil prices until June 1985 when crude oil markets were deregulated.

Figure 7.4.4.2 indicates that consumption taxes have been the single largest contributor to higher gasoline prices in Canada since 1981. About two-thirds of the gasoline price difference between the two countries can be attributed to higher consumption taxes in Canada. Between 1980 and 1987 Canadian taxes increased by 10¢/litre while U.S. gasoline taxes rose by 3.7¢/litre. On an ex-tax basis, Canadian prices did not exceed those in the U.S. until 1983 and have generally remained within 4 to 6¢ Can/litre since then.

Both countries have undergone significant changes in market structures but these changes have not affected both markets to the same extent. As a result, structural differences have developed that account for some of the current ex-tax price disparities.

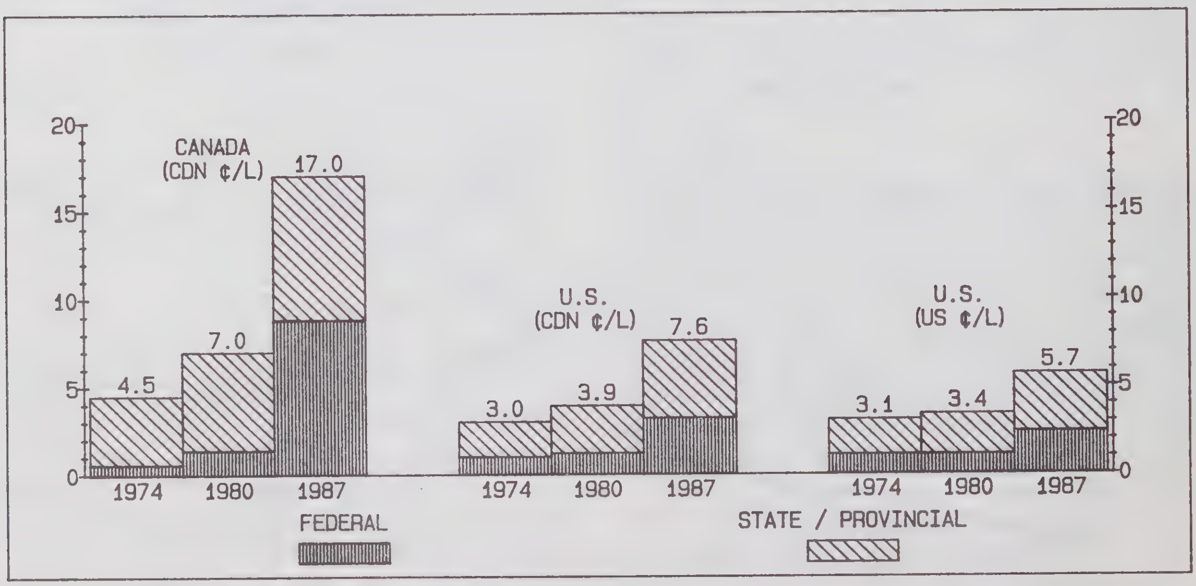
Economies of scale, in the form of higher throughputs per outlet, more customers per outlet and larger increases in gasoline demand, all favour U.S. markets.

The U.S. market has a greater concentration of higher-valued products, such as gasoline and aviation fuels, and a higher proportion of premium and unleaded gasoline sales.

Retailing innovations, such as C-stores and self-serve outlets, which broaden a retailer's revenue base and/or reduce operating costs, have been more extensively incorporated into the U.S. market than they have been in the Canadian retail network.

Price spreads among grades of gasoline and between types of service offered can also vary significantly between the two countries.

Figure 7.4.4.2
Consumption Taxes
(Canada vs U.S.)
cents / litre



8 Upstream Activity

- *According to mid-year estimates drilling rig utilization will decline to only 30% in 1989 reflecting oil price uncertainty and other factors.*

- *Although total established oil reserves increased in 1988, reserves from the key conventional category declined.*

8.1 Drilling Rig Activity

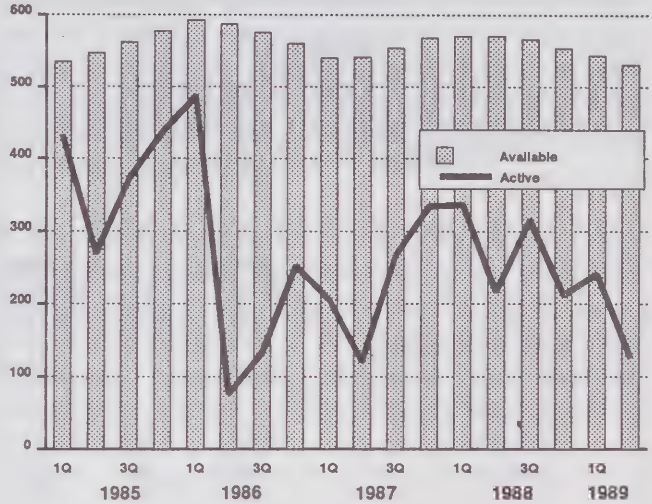
More than three-quarters of Canadian drilling rigs were reported idle during the second quarter of 1989. Drilling activity in the second quarter, normally a period of low activity because of spring breakup, averaged 127 active rigs compared with 217 recorded a year earlier. Despite the fact that the size of the rig fleet dropped about 40 to 530, second quarter utilization fell to 24% down from 38% a year ago. The low point in the quarter was recorded in the third week of April when only 95 rigs were operating.

The decline in industry cash flow as a result of last year's world crude oil price slump has fostered a cautious and prudent approach to drilling. Second-quarter drilling activity did not reflect the stabilization of crude oil prices which took place over the previous quarter, at about $US 20/bbl. Company exploration budgets were set during the previous year and were based on predictions of $US 12 to $15/bbl. The early cancellation of the Canadian Exploration and Development Incentive Program and a change in Alberta royalty terms, as well as corporate mergers, high interest rates and a strong Canadian dollar also helped to push drilling activity to lows recorded early in 1987.

On a provincial basis, both Alberta and Saskatchewan experienced severe cutbacks in drilling activity. Alberta averaged 86 active rigs compared with 154 a year ago for a utilization rate of about 21%. Saskatchewan registered 14 active rigs, 20 rigs less than last year. British Columbia recorded a modest growth as active rigs increased to 14 from 6.

Figure 8.1.
Drilling Rig Activity

Number of rigs



1989 Outlook

Earlier in the year analysts predicted 1989 drilling activity would be 15 to 20% lower than last year's level. However, according to early July estimates, the original forecast may have been optimistic. Based on expectations of continued low utilization rates in the second half of the year, utilization is expected to fall to 30% in 1989, a 40% decline from 1988. There is hope however, that improved and stable prices for both crude oil and natural gas could stimulate a renewal of interest and investment during the last half of this year. As well, operators are expected to take advantage of the last opportunity to use Alberta's royalty holiday program which ends in October.

8.2 Reserves

The Canadian Petroleum Association (CPA) publishes an annual review of oil reserves* in Canada. Table 8.2 illustrates the changes which occurred in established domestic oil reserves in 1988.

Table 8.2
Crude Oil and Equivalent
Remaining Established Reserves in Canada
millions of cubic metres

		Remaining Reserves end 1987	Net Change	Remaining Reserves end 1988
I	Conventional			
	Crude Oil			
	Alberta	631	-20	611
	Other	134	6	140
		765	-14	751
II	Frontier			
	North	92	- 2	90
	Eastcoast Offshore	82	50	132
		174	48	222
III	Pentanes	138	- 5	133
IV	Synthetic	263	29	292
V	Bitumen	151	71	222
	TOTAL	**1491**	**129**	**1620**

Mainly as a result of the continuing decline in Alberta reserves, established reserves of conventional crude oil in the western provinces declined slightly to 750 million cubic metres. Since 1969, when reserves in these areas peaked at 1.7 billion cubic metres, gross reserve additions of crude oil have been less than production. In 1988 approximately 80% of conventional crude production was replaced by reserve additions in the producing regions.

In the frontier areas, which include Norman Wells, the Mackenzie delta, Beaufort Sea, Arctic Islands and eastcoast offshore, reserves jumped almost 50 million cubic metres, or 28%, reflecting the first-time recognition of established reserves in the Terra Nova offshore oilfield. The eastcoast offshore and the Beaufort Sea account for 89% of frontier reserves.

Synthetic crude reserves, which are calculated on the basis of each plant's developed capacity, were up 30 million cubic metres, to 293 million cubic metres reflecting the extension of the operating permit for the Syncrude plant. Developed bitumen reserves jumped 70 million cubic metres, to 222 million cubic metres because of further development of some projects. Synthetic and bitumen reserves under active development now make up 32% of total crude oil and equivalent reserves.

** There are definitional differences between the CPA, provincial agencies' and NEB estimates. Oil reserves carried by the CPA are generally higher.*

9. Capital and Repair Expenditures in the Petroleum Industry

- *A mid-year survey of 1989 investment intentions in the petroleum industry indicates little change in plans from the beginning of the year.*

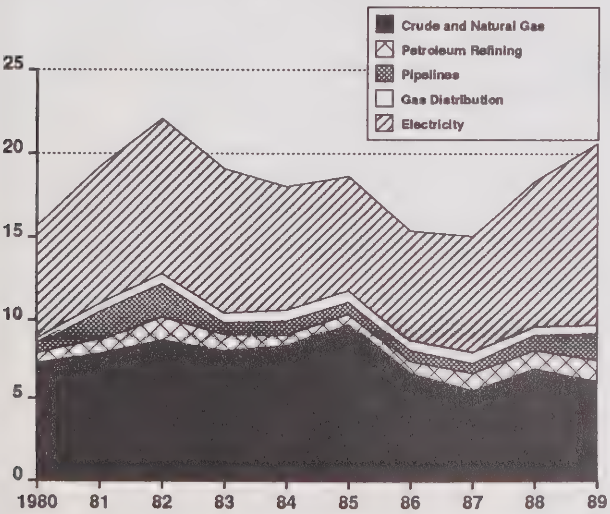
- *A pronounced shift in capital and maintenance expenditures from the upstream towards the downstream sector is still anticipated.*

In keeping with a similar survey conducted at the end of 1988, a mid-1989 survey of capital and repair expenditure intentions suggests that investment in the energy sector should surpass $20 billion in 1989, of which slightly less than half will be in the oil and gas industry. This represents an increase in spending (unadjusted for inflation) of about 12% vis-à-vis last year. Virtually all the increase should occur in the electric power industry as overall capital expenditures in the petroleum industry are still expected to remain at 1988 levels. Despite flat capital expenditures in the oil and gas industry, a significant shift in investment away from the upstream towards the downstream sector is anticipated.

The upstream sector could yield a decline in spending of over $800 million, to $6.1 billion, from last year. Exploration and development drilling in the conventional sector should fall $600 million to $2.4 billion, reflecting oil and gas price uncertainty, the phasing out of government drilling incentives, and relatively higher per unit discovery costs vis-a-vis foreign oil-producing regions. Increased merger activity has also been implicated in the decline in capital expenditures generally, and drilling activity specifically. Higher investment in production facilities and natural gas processing plants should, however, partially offset the reduction in exploration and development spending.

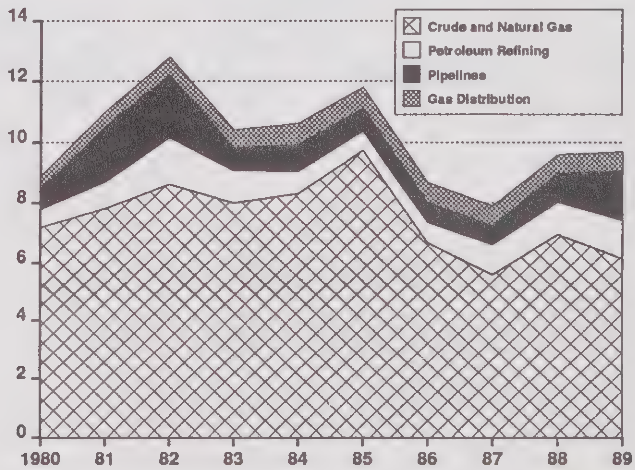
In the non-conventional sector, exploration and development expenditures are expected to fall by more than half, to $420 million. This dramatic reduction follows in the wake of the completion of the Newgrade Upgrader and Syncrude's Capacity Addition Program in 1988 and the postponement of several in situ oil sands projects originally slated for 1989.

Figure 9.1
Total * Energy Capital Expenditures
$CAN (Billions)



* *excludes coal and uranium mining*

Figure 9.2
Capital Expenditures in the Petroleum Industry
$CAN (Billions)

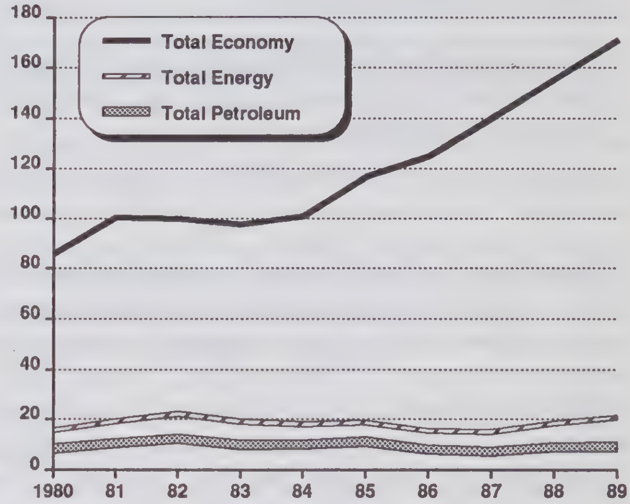


The pipeline companies, including those delivering natural gas to the export market, plan to invest heavily in new infrastructure in 1989. Total capital and maintenance expenditures are expected to be above $1.6 billion, almost $700 million more than last year. Moreover, another $600 million is expected to be spent on expanding gas distribution networks in urban areas.

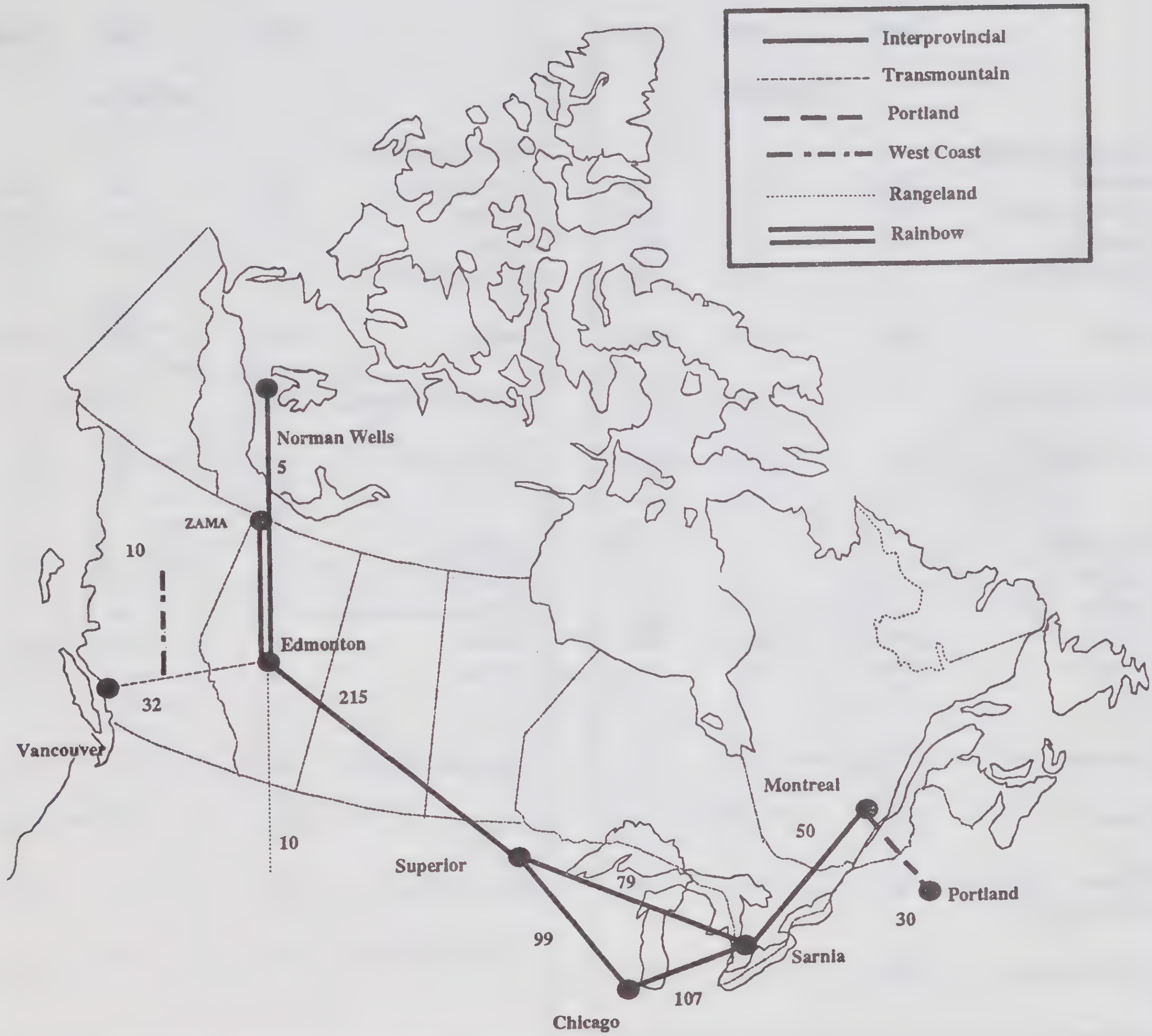
Expenditures in the petroleum refining sector are also expected to rise sharply, by $200 million to $1.3 billion, as refiners upgrade their facilities to meet more stringent product specifications, particularly for transportation fuels.

In the first half of the decade, the oil and gas industry consistently accounted for about 10% of total capital and repair expenditures in the economy. Since 1985, its share has steadily been eroded as economic growth has been stronger in other sectors of the economy. In 1989 the industry should account for only about 5% of the total.

Figure 9.3
Capital And Repair Expenditures
$CAN (Billions)



Appendix I
Major Crude Oil Pipelines In Canada
Location and Capacities
000 m^3/d



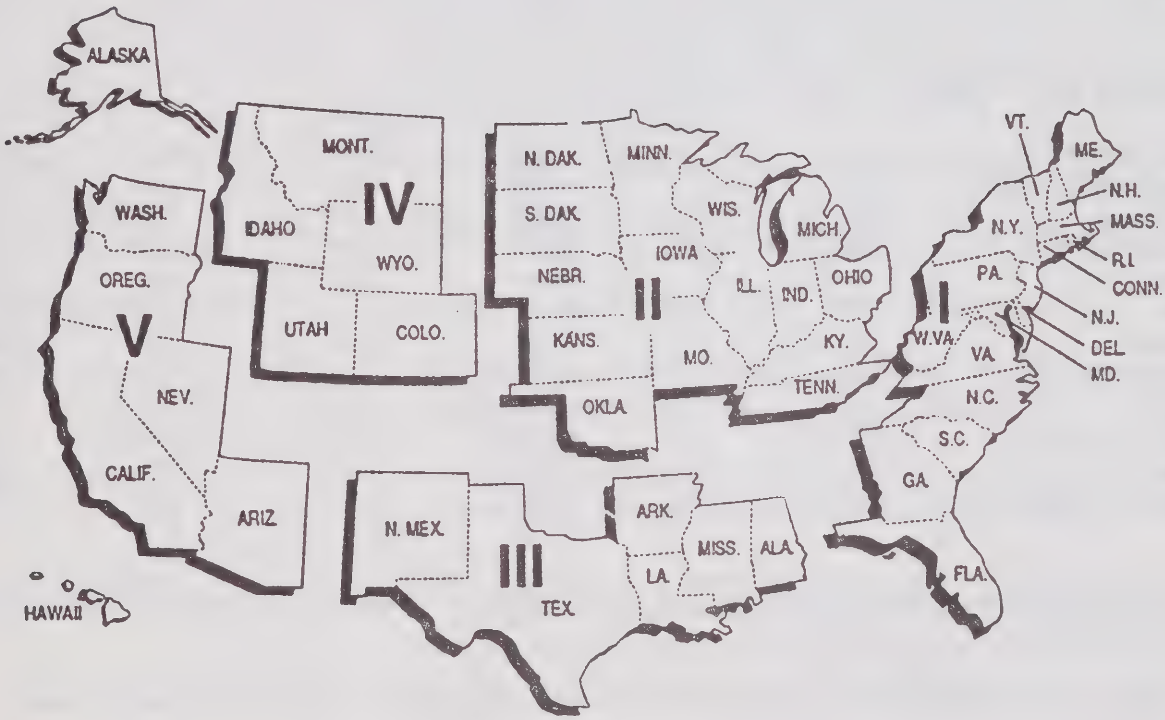
Appendix II
Light Crude Oil and Equivalent
Production and Disposition
(Second Quarter)

	1987	1988	1989
		(000 m^3/d)	
PRODUCTION			
Alberta	126.0	132.4	125.9
Other Regions	22.1	22.3	22.0
Synthetic	31.2	31.6	36.7
Pentanes Plus	16.4	16.7	16.5
Total	**195.7**	**203.0**	**201.1**
Inv.Draw/(Build)	0.2	0.6	1.1
Net Supply	195.9	203.6	202.2
DEMAND			
Atlantic	0	0	0
Quebec	8.4	14.3	9.0
Ontario	56.0	56.7	65.5
Prairies	50.0	46.6	52.1
B.C.	20.5	21.5	17.6
Domestic Demand	134.9	139.1	144.2
Exports	50.7	52.9	47.0
Diluent for Heavy (excl. recycled)	10.3	11.6	10.5
Total Demand	**195.9**	**203.6**	**202.2**

Appendix III
Heavy Crude Oil
Production and Disposition
(Second Quarter)

	1987	1988	1989
		(000 m^3/d)	
PRODUCTION			
Conventional	41.4	43.8	45.4
Bitumen	17.2	21.0	20.5
Diluent (incl.recycled)	11.0	12.2	11.8
Total	**69.7**	**77.0**	**77.7**
Inv.Draw/(Build)	4.2	6.3	1.5
Net Supply	73.9	83.3	79.2
DEMAND			
Atlantic	0.6	0.4	0
Quebec	2.5	3.4	4.2
Ontario	10.7	8.8	10.4
Prairies	4.4	4.1	9.1
B.C.	0.1	0.5	0.5
Domestic Demand	18.3	17.2	24.2
Exports	55.6	66.1	55.0
Total Demand	73.9	83.3	79.2
Recycled Diluent	0.8	0.6	1.3

Appendix IV
U.S. Petroleum Administration for Defense (PAD) Districts



Appendix V
Consumption Taxes on Petroleum Products
(June 1, 1989)

	Ad valorem Mogas	Ad valorem Diesel	Reg L	Reg UL	Gasoline Prem UL	Diesel
	(%)	(%)	(cents per litre)	(cents per litre)	(cents per litre)	(cents per litre)
FEDERAL TAXES						
Sales			3.56*	3.56*	3.67*	2.77*
Excise			8.5*	7.5*	7.5*	4.0
PROVINCIAL TAXES						
Newfoundland [(a)]	22	26	10.2*	10.2*	10.2*	11.7
Prince Edward Island	20	23	8.6*	8.6*	8.6*	8.7
Nova Scotia	20	21	8.9*	8.9*	8.9*	8.8*
New Brunswick	24.5 [(b)]	31.5	11.5*	9.8*	10.5*	11.4*
Quebec [(c)]			14.4	14.4	14.4	12.45
Ontario			13.3*	10.3*	10.3*	10.9*
Manitoba			9.8	8.0	8.0	9.9
Saskatchewan			12.0*	10.0*	10.0*	10.0*
Alberta			5.0	5.0	5.0	5.0
British Columbia [(d)]	22.5 [(e)]		9.69*	7.69*	7.69*	8.13*
Yukon			4.2	4.2	4.2	5.2
Northwest Territories	17	(f)	8.1*	8.1*	8.1*	6.9*

(a) *The gasoline tax is reduced by 1.5 cents per litre in the region between the Quebec border and Red Bay in Labrador.*

(b) *This applies to all gasolines. There is an additional 2.2 cents per litre surcharge on regular leaded gasoline.*

(c) *Reduced by varying amounts in certain remote areas and within 20 kilometers of the provincial and U.S borders.*

(d) *Additional transit tax of 3.0 cents per litre in Vancouver.*

(e) *This applies to unleaded gasoline. Taxes on leaded gasoline and diesel fuel 2.0 and 0.44 cents per litre higher, respectively, than the unleaded tax.*

(f) *85% of gasoline tax.*

** Changed since last quarter.*

Glossary

Bitumen	A naturally occurring viscous mixture composed mainly of hydrocarbons heavier than pentane, which may contain sulphur compounds and which in its natural state is not recoverable at a commercial rate through a well.
Conventional areas	Those areas of Canada that have a long history of hydrocarbon production. Conventional areas are also referred to as nonfrontier areas.
Crude oil and equivalent	Includes crude oil, synthetic crude, oil produced from oil sands plants, and condensate.
Established reserves	Those reserves recoverable under current technology and present and anticipated economic conditions, specifically proved by drilling, testing or production, plus that judgement portion of contiguous recoverable reserves that are interpreted to exist, from geological, geophysical or similar information, with reasonable certainty.
Feedstock	Raw material supplied to a refinery or petrochemical plant.
Heavy crude oil	Loosely applied, crude oils with a low API gravity (high density).
Initial established reserves	Established reserves prior to the deduction of any production.
In situ recovery	With reference to oil sands deposits, the use of techniques to recover bitumen without the necessity of mining the sands.
Light crude oil	Crude oil with a high API gravity (low density). Generally includes all crude oil and equivalent hydrocarbons not included under heavy crude oil.
Natural gas liquids	Those hydrocarbon components recovered from raw natural gas as liquids by processing through extraction plants, or recovered from field separations, scrubbers or other gathering facilities. Includes the hydrocarbon components ethane, propane, butane and pentanes plus, or a combination thereof.
Oil sands	Deposits of sands and other rock aggregate that contain bitumen.
Pentanes plus	Also referred to as condensate. A volatile hydrocarbon liquid composed primarily of pentanes and heavier hydrocarbons. Generally a by-product obtained from the production and processing of natural gas.
Productive capacity	The estimated production level that could be achieved, unrestricted by demand, but restricted by reservoir performance, well density and well capacity, oil sands mining capacity, field processing and pipeline capacity.
Remaining established reserves	Initial established reserves less cumulative production. See established reserves

Shut-in capacity	The unused production capability of currently producing oil and gas wells plus the total production capability of all shut-in oil and gas wells, regardless of whether or not they are connected to surface gathering and production facilities.
Synthetic crude oil	Crude oil produced by treatment in upgrading facilities designed to reduce the viscosity and sulphur content.

The Canadian Oil Market

Vol. V, No.3, Third Quarter 1989

Energy, Mines and Resources Canada
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THE CANADIAN OIL MARKET

Vol. V, No. 3, Third Quarter 1989

Canadian Oil Markets and Trade Division
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Table of Contents

List of Figures

Figure	Title	Page

List of Tables

The Canadian Oil Market

Overview

- *The largest decline in seasonally-adjusted demand for petroleum products in the last five years occurred in the third quarter. This decline, in combination with that of the second quarter, has restored consumption to the average 1988 level.*

- *A drop in demand for transportation fuels accounted for much of the decrease. Demand for heavy fuel oil remained strong. A sharp increase in heavy fuel oil consumption in Quebec, was mainly attributed to the reactivation of the thermal electric generation plant at Tracy.*

- *National stock levels of crude oil and refined products at the end of September were about 3% lower than last year's comparable level, with declines most notable in Atlantic Canada.*

- *Current National Energy Board projections anticipate a 6% decline, to 122 000 m^3/d, in the productive capacity of Alberta light conventional crude oil capacity in 1990. Supply from other provinces and production of synthetic crude and pentanes plus is not expected to change next year.*

- *Exports of crude oil and equivalent were down for the third consecutive quarter, principally reflecting the decline in conventional light crude oil production and higher domestic demand for Canadian heavy crude.*

- *Canada's energy trade surplus in the third quarter, almost $1.5 billion, was virtually identical to that recorded a year ago.*

- *The tightening of the light, sweet crude market in Canada is having an impact on the determination of crude oil posted prices and the relationship between Canadian and American prices.*

- *Drilling rig activity was at a low level in the third quarter, with more than two-thirds of available Canadian rigs idle. Prospects for 1990 are more optimistic as increased demand for natural gas will likely stimulate higher levels of exploration and development activity.*

1. Domestic Demand

- *The largest decline in seasonally adjusted demand in the last five years occurred in the third quarter of 1989.*

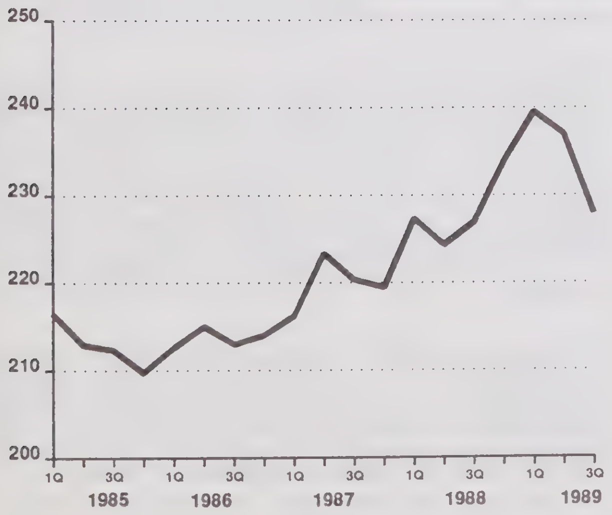
- *Demand declined for all products, except heavy fuel oil as thermal electricity requirements continued to grow.*

- *Over the last five years Alberta has been the only Prairie province to experience growth in product consumption.*

1.1 Seasonally Adjusted

Seasonally adjusted sales of refined petroleum products in Canada averaged 228 000 m^3/d in the third quarter of 1989. This represents a decline of almost 4% from the previous quarter, and puts consumption back at the average 1988 level. As illustrated in figure 1.1.1, this is the largest single quarterly decrease in the last five years.

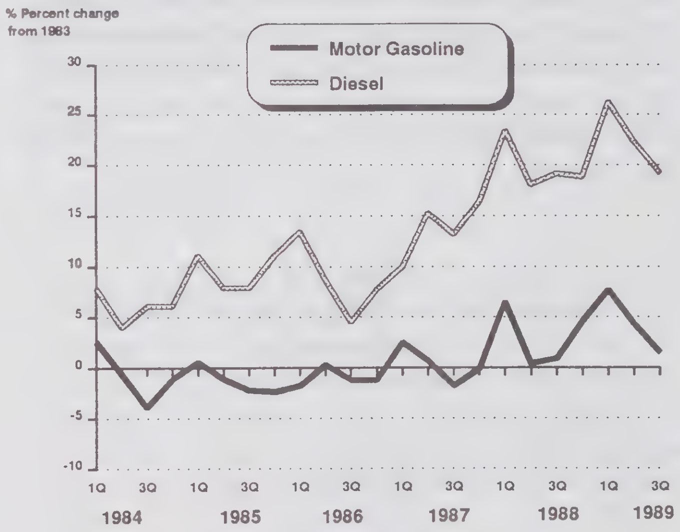
Figure 1.1.1
Total Petroleum Product Consumption
(Seasonally Adjusted)
000 m^3/d



Some of the factors which have contributed to the sharp decline in the third quarter include the lagged impact of the rise in gasoline prices in the middle of the second quarter and lower economic growth.

Much of the decline was accounted for by a 2.5% decrease in demand for transportation fuels. Domestic sales of motor gasoline and diesel fuel fell to 92 000 m^3/d and 45 000 m^3/d respectively. These two fuels account for 60% of total product sales. Figure 1.1.2 indicates that, as a result of declines in the second and third quarter, consumption of gasoline was below last year's average, and only 1.5% higher than the average consumption in 1983.

Figure 1.1.2
Trends in Motor Gasoline and Diesel Fuel Consumption
(Seasonally Adjusted)



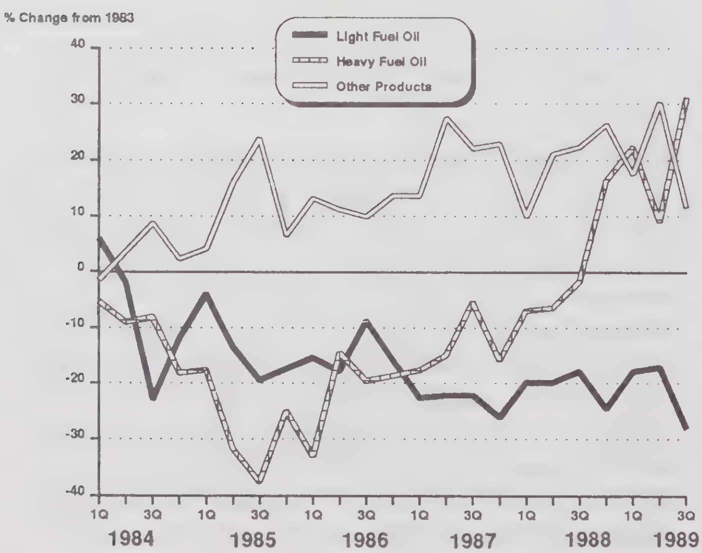
Higher gasoline prices have had a negative effect on Canadian demand. In addition, according to Statistics Canada, same day visits by Canadians to the United States were up 19% in the first nine months of 1989 compared with the same period in 1988. Much of the increase reflects travel by Canadians, especially those living in border areas, to the United States to purchase less expensive American consumer products including gasoline. In contrast, higher prices for Canadian goods, including gasoline, have contributed to a reduction in the number of American visitors to Canada. These changes in automobile tourist traffic have been a factor in the drop in Canadian gasoline consumption.

On a seasonally adjusted basis, light fuel oil demand declined by 13%, to 18 500 m^3/d, in the third quarter. This represents a 12% decrease from the same period last year. This is largely due to the warmer weather this September.

Sales of "other" petroleum products also dropped off significantly in the third quarter, to 43 000 m^3/d. A decline in production of petrochemical feedstocks, attributable to a maintenance shutdown in September at Polysar and a general weakening of international petrochemical markets, was the major contributor to the decline in the sales of "other" products.

Heavy fuel oil continued to experience large increases in sales . On a seasonally adjusted basis, consumption of heavy fuel oil reached 29 000 m^3/d in the third quarter, a 20% increase from the second quarter and 33% higher than the same period last year. Low water levels have been forcing utilities to switch to thermal electricity generation, thereby increasing demand for heavy fuel oil particularly in Quebec and the Maritimes. In figure 1.1.3 the consumption patterns for non-transportation fuels depict the steady growth in heavy fuel oil demand during the last year.

Figure 1.1.3
Trends in Non-Transportation Fuel Consumption
(Seasonally Adjusted)



Despite the declines in consumption for "main" petroleum products in the last two quarters, seasonally adjusted sales for the first nine months of 1989 were up nearly 4% from the same period last year, mainly reflecting strong growth in heavy fuel oil sales. However, there are early indications that the four-year trend of sustained petroleum product consumption growth is over. Assuming a continuation of the current environment, i.e. slow economic growth, higher product prices and an appreciating dollar, a further decline in consumption would not be unexpected.

1.2 Regional Consumption

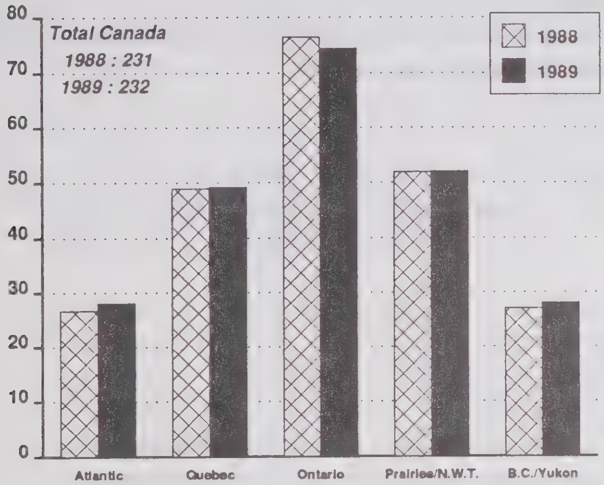
After growing at over 5% in the first half of 1989, product consumption slowed significantly in the third quarter. Actual consumption of refined petroleum products, before seasonal adjustments, averaged 232 000 m^3/d in the third quarter, an increase of less than 0.5% over the same quarter last year. Increases in the Atlantic region and British Columbia were countered by declines in Ontario. Reasons for this slowdown are discussed in section 1.1.

In the Atlantic provinces, where heavy fuel oil (HFO) accounts for more than 25% of product consumption, a 20% rise in demand for that product led to a 5.5% increase in total product use. The electric power industry continued to rely on HFO to compensate for shortfalls in hydro-generation caused by low water levels. Sales of transportation fuels declined by more than 3% in the third quarter compared with the same period last year.

The largest rise in HFO consumption was in Quebec where sales were up by nearly 45% over last year. This is mainly due to the reactivation of the thermal electric generation plant in Tracy. The plant, which was reactivated last fall, is currently burning about 2 000 m^3/d of HFO and is expected to double its consumption by mid-December.

The increase in HFO consumption in Quebec was countered by a 33% decline in light fuel oil demand. Milder temperatures this year compared to last year, particularly in September, accounted for the drop. Overall, total product demand in Quebec was virtually unchanged in the third quarter compared with last year.

Figure I.2
Regional Petroleum Product Consumption
(Third Quarter)
000 m^3/d



Ontario accounts for nearly a third of Canada's product consumption. A decline of almost 3% in this region in the third quarter offset most of the increases in the other regions. Motor gasoline, which accounts for a little less than half of Ontario's product sales, decreased by about 5%. As mentioned earlier, increased Canadian automobile travel to the U.S. and a reduction in the number of American visitors to Canada were major contributors to this decline. Sales of "other" products also fell by nearly 18%, influenced by the drop in petrochemical feedstock demand.

In the Prairie provinces, transportation fuels account for nearly three quarters of product consumption. Both motor gasoline and diesel oil registered decreases in the third quarter, with demand down about 2% and 4%, respectively. These declines were countered by a 9% increase in sales of "other" products so that total Prairie product consumption was up marginally.

British Columbia was the only region to experience growth in demand for all products, with total consumption up almost 5% from last year. The largest increase was in motor gasoline sales, which rose by more than 6%.

1.3 International Oil Consumption

Preliminary data for sales in the OECD markets indicate conflicting developments with an overall increase in sales of less than 1%. North American consumption was down, led by the United States where gasoline demand fell 1%. Total product sales have fallen 1% in the United States so far this year.

Table 1.3
International
Petroleum Product Consumption*
% Change 1988/1989**
(Third Quarter)

Product	Canada	U.S.A.	Europe**	Japan
Motor Gasoline	0.8	-0.8	0.9	7.6
Middle Distillates	-1.9	1.6	1.8	6.3
Heavy Fuel Oil	29.7	-10.8	-5.3	-27.9
Other Products	-7.1	-2.7	1.2	3.4
Total	0.4	-1.8	0.3	3.5

* *Before seasonal adjustment*
** *Preliminary*

In Europe sales were up slightly with declines in Germany and Italy offsetting growth in the United Kingdom and France. In contrast to Canada, demand for heavy fuel oil in France was down significantly. Sales in Japan continued to be very strong, rising 4% in the third quarter.

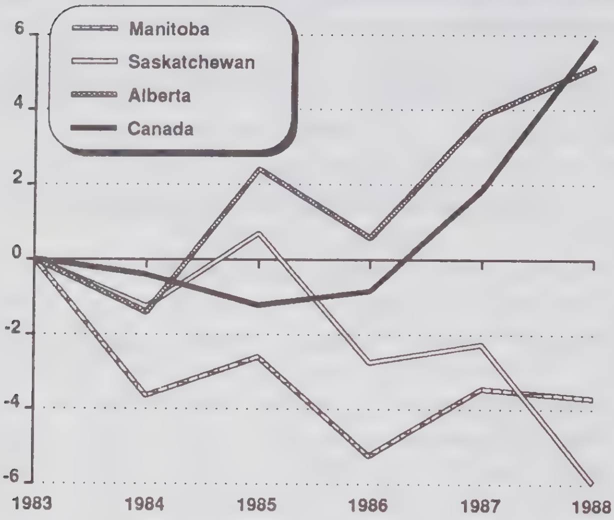
1.4 Review of Petroleum Product Consumption In The Prairies, 1983-1988

Since the economic recovery in Canada which began in 1983 the level of refined petroleum product consumption in the Prairie region has remained relatively flat, rising only 1% from 1983 to 1988. Whereas national product sales rebounded between 1986 and 1988, rising 15 000 m^3/d or 6% to 229 000 m^3/d, virtually all this growth occurred in the other regions as sales in the Prairies increased by barely 1 000 m^3/d, to 45 000 m^3/d.

Figure I.4.1

Percentage Change in Total Product Consumption

% Change from 1983



What little growth there has been in the Prairies since the recovery has been confined to Alberta. Product consumption actually fell by about 5% in both Manitoba and Saskatchewan. The 5% increase in Alberta can be largely explained by a 20% rise in sales of "other" products which reflects the start-up, in the mid-eighties, of a petrochemical plant that uses refinery-supplied petrochemical feedstocks.

The lackluster growth in product sales in the Prairies since 1983 is the result of a combination of factors. First, economic growth in the region did not keep pace with the rest of the country. Two of the region's key industries, agriculture and petroleum, fared relatively poorly over the period. Although the Manitoba economy performed reasonably well, the same cannot be said for either Saskatchewan or Alberta. As a consequence, the region's gross domestic product as a percentage share of national GDP fell from 21% to 17% over the six-year period. Second, population growth in the region also lagged behind the national average rising by only 2.5% vis-a-vis 4.5% nationwide.

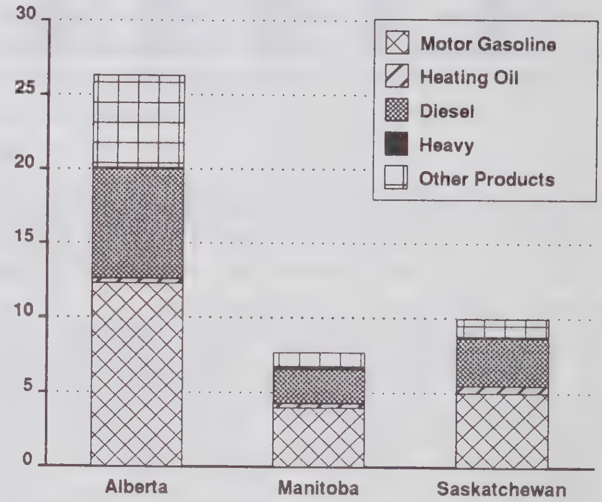
It would appear that the divergent trends in transportation fuel sales observed in the Prairies relative to the nation as a whole can be largely explained by the above-noted economic and demographic disparities. While gasoline sales grew by 3% nationally they declined by 4% in the Prairies, mostly in Saskatchewan. By the same token, a 6% rise in diesel fuel demand was only a third of the growth recorded nationwide.

Figure I.4.2

Average Petroleum Product Sales

(1983-1988)

000 m^3/d



Yet the Prairies continued to consume significantly more gasoline and diesel per capita than the other regions. Over the 1983-88 period gasoline sales averaged about a third higher than the national average, with sales in Alberta alone having been as much as 50% higher per capita.

The higher per capita consumption reflected the fact that there are a greater number of vehicles per capita in the Prairies. Moreover, because of the region's drier climate, vehicles last longer. As a consequence, the fleet is older and less fuel efficient. There is also a higher proportion of light trucks and vans (which relates to the region's large agricultural sector) as opposed to more fuel efficient automobiles. The greater dispersion within and between communities appears to be another factor: the number of kilometers driven in the Prairies is generally higher than in other regions. Lower gasoline prices, reflecting for the most part lower provincial sales taxes, likely also contributed to higher sales.

However, the narrowing of the gap between gasoline sales per capita in the Prairies and the other regions suggests that the role played by some of these variables in supporting higher consumption may be lessening. Fuel-saving farming practices, greater urbanization and some recent improvement in fuel efficiency appear to have, along with the economic and demographic factors, contributed to the reduction in motor gasoline consumption.

Diesel fuel demand has also been disproportionately high in the Prairies. In fact it has averaged about 75% higher per capita than the national average over the six-year period. One reason for this high level of consumption relates to the fact that a lot of the machinery and equipment in the petroleum and agricultural sectors use diesel fuel. Also, as previously mentioned, there is a positive correlation between population dispersion and fuel consumption. This correlation should be stronger for diesel than for gasoline, given that a higher proportion of total diesel fuel demand emanates from that part of the transportation industry primarily involved in long-distance, inter-regional hauls (i.e. the railway and trucking industries).

In contrast to gasoline and diesel fuel, sales of light and heavy fuel oil have been markedly below the national average. The region consumed only about 30% as much light fuel oil (and kerosene) per capita, and only about 10% as much heavy fuel oil. In both cases the low and declining level of sales reflected an increasing reliance on natural gas in lieu of light fuel oil in the space heating sector, and of heavy fuel oil in the industrial sector.

Most of the decline in fuel oil use occurred in Manitoba and Saskatchewan. In Alberta, where natural gas has made its greatest inroads into the space heating and industrial markets, the declines were not nearly as dramatic. In fact, sales in Alberta increased in 1988 from the year before, suggesting little potential left for further fuel switching from oil to natural gas in the province. This situation could also soon apply in the other two provinces in light of the small volumes of fuel oil currently consumed there.

Transportation costs are a much larger component in the selling price of natural gas than they are in the case of crude oil, and implicitly oil products. The pipeline cost of delivering natural gas to eastern Canada has typically been about five times higher, on an energy equivalent basis, than that associated with delivering crude oil to the same market. Therefore, on the assumption that natural gas is priced to be competitive with oil at the marginal market (e.g. Toronto or Montreal), it becomes increasingly cheaper vis-à-vis crude oil and its products, the closer consumption is to the source of production. This built-in price bias largely explains why natural gas has been significantly cheaper and in far greater demand in the Prairies, compared with other regions where it faces stiffer competition from light and heavy fuel oil.

Per capita demand for "other" products in the Prairies has essentially been on a par with the rest of the country. Sales rose about 15% between 1983 and 1988 with the incremental consumption largely attributable to higher petrochemical feedstock sales in Alberta. What distinguishes "other" product sales in the Prairies from the rest of Canada is the disproportionately high level of demand for asphalt. About 30% of Canada's asphalt sales occur in the Prairies while only 17% of its population resides there. As in the case of transportation fuel consumption, this higher-than-average demand for asphalt, mostly from the road paving industry, reflects the greater dispersion of population in the region.

2. Refinery Utilization and Stocks

- *In line with marginal sales growth, refinery utilization rose slightly during the third quarter of 1989.*
- *The ratio of imports to total crude receipts increased.*

2.1 Refinery Utilization

Crude oil run to stills (including butanes, other feedstocks and partially processed oils) increased marginally during the third quarter of 1989 when compared with the same period last year. The national refinery utilization rate (based on 300 000 m^3/d of refinery capacity), registered a healthy 87%. Regional refinery details are illustrated in table 2.1.

Table 2.1
Refinery Utilization
(Third Quarter)

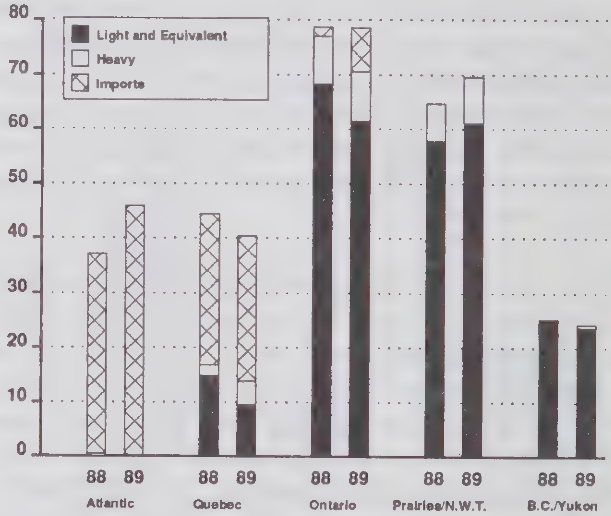
	Crude Run 1988	Crude Run 1989	Utilization 1988	Utilization 1989
	000 m^3/d		%	
CANADA	261	262	87	87
Atlantic	45	46	83	85
Quebec	45	43	92	87
Ontario	79	79	82	82
Prairies	66	70	91	94
B.C.	26	24	96	91

The overall increase in throughput matched a slight rise in petroleum product demand. The drop in Quebec refinery throughput can be attributed to the impact of refinery maintenance programs and increased product imports. Increased shipments of semi-refined product from Alberta to British Columbia had a positive effect on Prairie throughput.

Third-quarter refinery receipts of crude oil and equivalent feedstocks averaged 259 000 m^3/d (including 9 000 m^3/d of partially processed oil), 1% (or 2 000 m^3/d) less than the third quarter of last year. Imports of crude oil increased by 6% to just over 80 000 m^3/d while domestic feedstocks fell by 3% to 179 000 m^3/d.

Receipts of conventional light crude oil fell by almost 9%, to 113 000 m^3/d, with all this drop recorded in Ontario and Quebec. Synthetic crude and pentanes plus receipts, totalling 25 000 m^3/d and 4 000 m^3/d respectively, remained relatively unchanged. Heavy crude oil receipts increased by 22%, to 23 000 m^3/d with most of the increase recorded in Quebec and the Prairies.

Figure 2.1
Crude Oil and Equivalent Refinery Receipts by Region
(Third Quarter)
000 m^3/d



In Ontario and Quebec the proportion of both imports and domestic heavy crude receipts relative to light crudes continued to increase. Much of this change can be attributed to the decline in conventional light crude output (see section 3).

Total refinery demand for the fourth quarter of 1989 is projected to remain at 259 000 m^3/d, unchanged from the third quarter level. Based on October refiners' submissions to the National Energy Board (NEB), domestic crude oil receipts are forecast to increase by 5% while imports are expected to fall by 10%. Refinery demand for 1990 is programmed to be only 2% higher than the estimated 1989 average of 258 000 m^3/d.

2.2 Stocks

As illustrated in table 2.2.1, closing crude oil and refined petroleum product stocks for the third quarter of 1989 totalled 14.3 million m^3, 3% (or 400 000 m^3) less than a year earlier. Petroleum product stocks (representing about 84% of total stocks) remained unchanged while crude oil fell by 13%.

On a year-over-year basis changes in stock levels were concentrated in the Atlantic region where crude and petroleum product stocks fell by 21% and 4%, respectively. With respect to petroleum products, Quebec registered an 8% increase while stocks in Ontario fell by 5%.

During the third quarter, refiners in Quebec drew down crude oil stocks significantly, reflecting tight domestic light crude supply. As a result of this decline and a lower-than-normal build of products, the national stock build which generally occurs in the third quarter was only about half as much as in previous years.

Table 2.2.1

Closing Crude and Product Inventories
(End September)
000 m^3

	Crude 1988	Crude 1989	Product 1988	Product 1989	Total 1988	Total 1989
CANADA	2740	2370	11990	11910	14730	14280
Atlantic	1240	980	1940	1850	3180	2830
Québec	720	540	2560	2780	3280	3320
Ontario	500	550	3810	3630	4310	4180
Prairies	180	220	2490	2500	2670	2720
B.C.	100	80	1190	1150	1290	1230

Compared with end-September 1988 levels, most "main" petroleum products, with the exception of diesel fuel, registered increases. Heating oil recorded the largest jump, up 2% from a year earlier. The "other" petroleum products category (including jet fuel, petrochemicals and asphalt), comprising about 30% of total petroleum product stocks, declined marginally.

By the end of the quarter, the ratio of stocks to consumption for crude oil and petroleum products represented about 61 days of forward consumption, three days less than a year earlier. If the Atlantic region was excluded from the calculation of this ratio, because a large portion of product shipments are directed to the export market and the region is not pipeline-connected to western Canadian supply, the ratio of stocks to consumption would be 56 days compared with 61 days last year.

Table 2.2.2

Closing Product Inventories
(End September)

	000 m^3 1988	000 m^3 1989	Days* 1988	Days* 1989
All Products	11990	11910	52	51
"Main" Products	8460	8470	48	47
Motor Gasoline	3580	3610	39	38
Heating Oil	1650	1680	101	108
Diesel Oil	2290	2190	46	45
Heavy Fuel Oil	940	950	51	45
"Other" Products	3530	3480	73	70

** Ratio of stocks to consumption*

The stocks discussed above do not include estimates of crude held in pipeline tankage. If these stocks were included, the ratio of stocks to consumption would increase by 7 days to 68 days of forward consumption. This ratio is 3 days higher than the 65 day average for the Organization for Economic Cooperation and Development (OECD) countries. If public (government owned and entity stocks held for emergency purposes) were included, the OECD average would increase to 93 days.

Table 2.2.3

Ratio of Stocks to Consumption
(End September)
Days

	Crude 1988	Crude 1989	Product 1988	Product 1989	Total 1988	Total 1989
CANADA	12	10	52	51	64	61
Atlantic	45	35	70	65	115	100
Québec	14	11	51	55	65	66
Ontario	7	7	50	45	57	52
Prairies	4	5	51	52	55	57
B.C.	4	3	45	46	49	49

3. Crude Oil Supply and Disposition

- *As a result of a significant decline in exploration activity, coupled with the "normal" decline in productive capacity, Alberta light conventional crude oil capacity is forecast to drop 6% in 1990.*

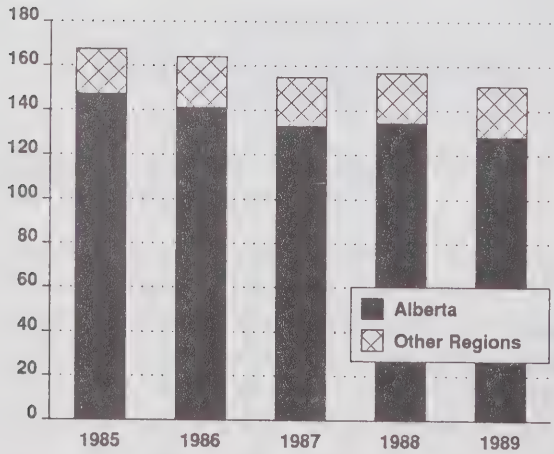
- *Heavy crude oil capacity in 1990 is expected to remain unchanged from 1989.*

3.1 Light Crude Oil and Equivalent Supply and Disposition

Conventional light crude oil productive capacity in Alberta fell by 5%, or more than 7 000 m^3/d, to 128 500 m^3/d in the third quarter of 1989. About half of the decline is attributable to a downward revision by the NEB in its short-term capacity forecast. As discussed in more detail in section 8, the revised forecast reflects the sharp fall-off in total exploration activity this year as well as a switch from oil to natural gas exploration. In other regions of western Canada conventional supply was down slightly, to 23 000 m^3/d.

According to current industry forecasts domestic oil output will be about 6 to 8% lower than previous estimates for the remainder of 1989 and 1990.

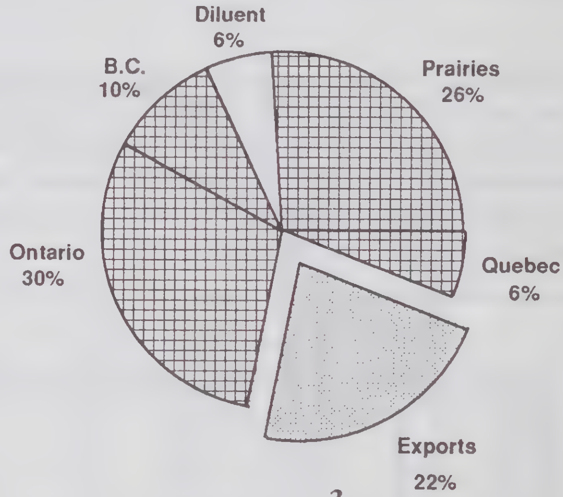
Figure 3.1.1
Conventional Light and Medium Crude Oil Productive Capacity
(Third Quarter)
000 m^3/d



The reduction to the Alberta capacity forecast, effective August 1989, resulted in a decline in "shut-in" capacity of 5 000 m^3/d from the second quarter to the third quarter of 1989. Despite this drop, much of the reported shut-in of 4 000 m^3/d during the third quarter was artificial, reflecting "overstated" capacity in July. Demand for light crude continued strong and there were no transportation constraints.

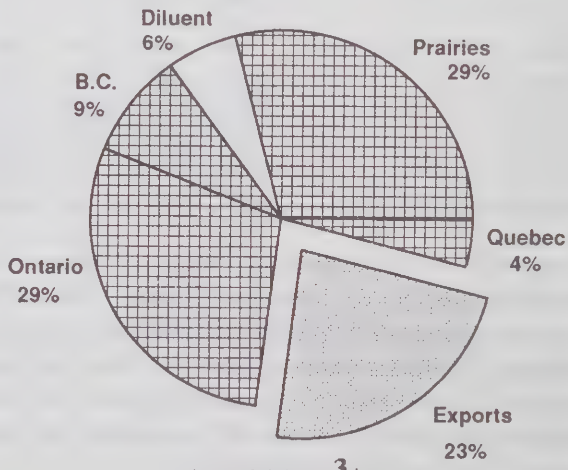
Figure 3.1.2
Light Crude Oil and Equivalent* Disposition
(Third Quarter)

1988



214 000 m^3/d

1989



196 000 m^3/d

* *Includes inventory draw of 5 000 and 2 000 m^3/d in 1988 and 1989*

Synthetic crude production, at 31 000 m^3/d, was lower (by 3 000 m^3/d) in the third quarter compared with the same period last year. All of the decline occurred at the Syncrude operation, reflecting a coker turnaround in July/August that was extended because of labour problems. At Suncor, output was about 5% higher.

Total production of light crude oil and equivalent (including pentanes plus used for diluent) declined about 13 000 m^3/d, or 6%, in the third quarter of 1989 compared with the third quarter of 1988. The drop was spread over both domestic and export markets. Much of the decline in the domestic market occurred in Ontario and Quebec.

1990 Forecast

The most recent supply forecast prepared by staff of the NEB, incorporates a less optimistic view than previous estimates. Conventional light crude oil productive capacity in Alberta in 1990 is forecast to decline 6% to 122 000 m^3/d. More than half the decline is attributable to the aforementioned revision. Over the medium term however, Board staff continue to forecast a 2 to 3% annual rate of decline in productive capacity.

Including to supply from other regions, and synthetic and pentanes plus production, output in 1990 is expected to be virtually the same as in 1989.

On the demand side, according to refiners' October estimates, deliveries are forecast to decline 3% to 141 000 m^3/d. Exports are also expected to decline by 6% to 43 000 m^3/d.

Table 3.1

Light Crude Oil and Equivalent Production and Disposition

(Annual)

000 m^3/d

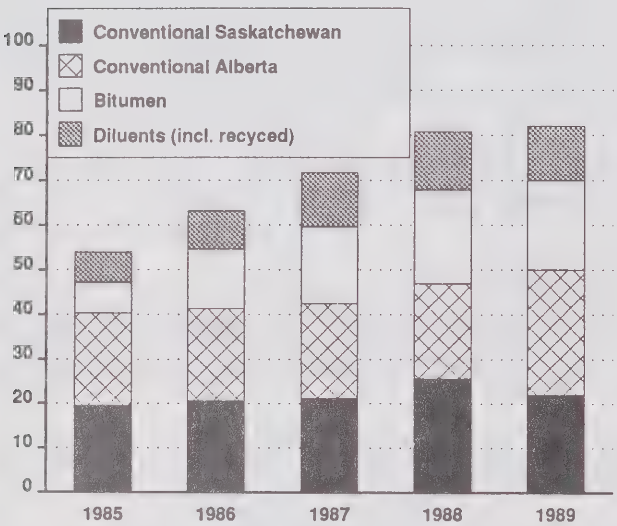
		1988	1989	1990
I.	Alberta Productive Capacity	137	129	122
	Shut-in	2	4	2*
II.	Production			
	Alberta	135	125	120
	Other Regions	23	23	23
	Synthetic	32	33	33
	Pentanes Plus	19	19	19
		209	200	195
	Inv. Draw	2	3	-
	Total Supply	211	203	195
III.	Demand			
	Domestic	149	145	141
	Export	50	46	43
	Diluent	12	12	11
	Total Demand	211	203	195

**About 2% of capacity to allow for operational problems and unforeseen downtime.*

3.2 Heavy Crude Oil Supply and Disposition

As has been the case for the last year or more, heavy crude capacity in the third quarter remained unchanged from the same period a year earlier. Total blended supply was 82 000 m^3/d, composed of 50 000 m^3/d of conventional capacity, 20 000 m^3/d of bitumen and 12 000 m^3/d of diluent. A marginal increase in conventional supply was offset by a decline in bitumen.

Figure 3.2.1
Heavy Crude Oil Productive Capacity
(Third Quarter)
000 m^3/d

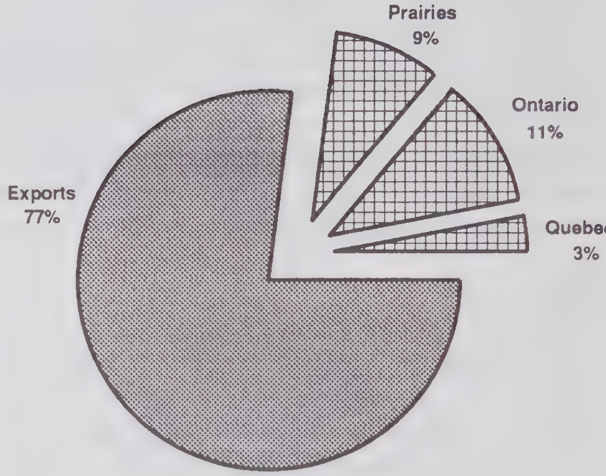


Although the level of shut-in, at 2 500 m^3/d, was lower in the third quarter of 1989 than in 1988, it was still considered to be high, given continued strong demand and adequate pipeline transportation capacity. It may be that heavy crude capacity has also been overestimated.

While domestic receipts were up 20% in the third quarter, exports fell by 9%, reflecting flat supply.

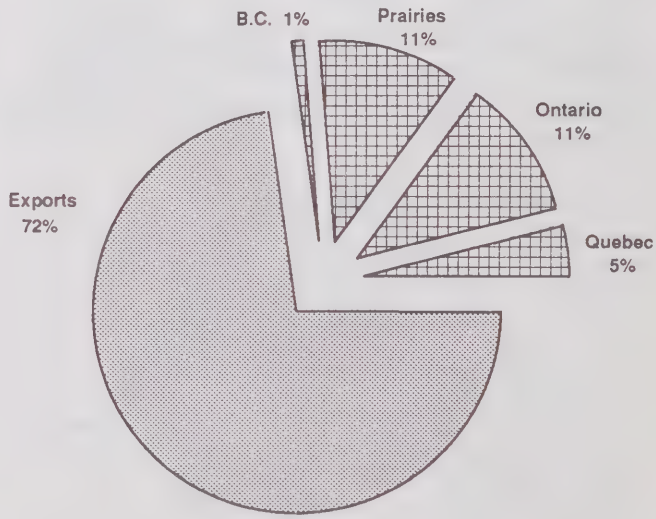
Figure 3.2.2
Heavy Crude Oil Disposition*
(Third Quarter)

1988



80 000 m^3/d

1989



80 000 m^3/d

** Includes inventory draw of 2 000 in 1988*

1990 Forecast

As illustrated in table 3.2, heavy crude production in 1990 is forecast to be down marginally, compared to 1988 and 1989. Exploration and development for heavy crude continues to be flat for much the same reasons as for light crude. Analysts do not expect any real increases in crude prices in 1990. Until prices and other market circumstances improve, heavy crude exploration activity is not expected to intensify.

Refiners continue to forecast increased demand for heavy crude next year. Total demand could reach 26 000 m^3/d, led by increases in Quebec and the Prairies. After peaking at 63 000 m^3/d in 1988, exports are projected to fall to 51 000 m^3/d in 1990.

Table 3.2

Heavy Crude Oil
Production and Disposition
(Annual)
000 m^3/d

		1988	1989	1990
I	**Productive Capacity**	81	80	80
	Shut-in	3	3	2*
II	**Production**			
	Conventional			
	Alberta	23	25	26
	Saskatchewan	22	20	20
	Bitumen	21	20	20
	Diluent	12	12	12
	Total	78	77	78
	Inventory Draw	3	2	-
	Total Supply	81	79	78
III	**Demand**			
	Domestic	18	22	26
	Exports	63	57	52
	Total Demand	81	79	78

* *About 2% of capacity to allow for operational problems and unforeseen downtime.*

4. Pipelines

- *Throughput on main trunk lines in the third quarter was down due to lower Canadian crude production.*

- *Interprovincial Pipe Line expects lower throughputs for 1990.*

4.1 Trans Mountain Pipe Line Throughput

During the third quarter of 1989, Trans Mountain Pipe Line (TMPL) throughput averaged almost 26 000 m^3/d, down 7% from the same period a year ago and 13% from the previous quarter.

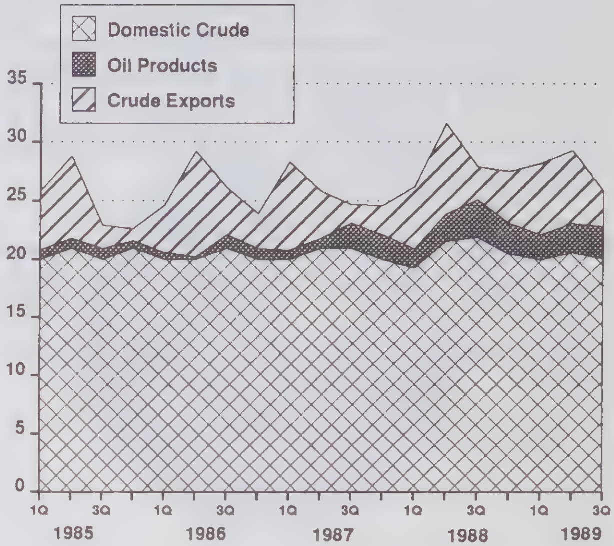
Total deliveries to the Vancouver area (Burnaby) refineries decreased by about 2 000 m^3/d (11%), to 20 000 m^3/d per day, relative to the same period last year, but were almost the same as in the previous quarter. Semi-refined products shipped from Edmonton at 5 000 m^3/d, were 3 000 m^3/d higher than those of the third quarter 1988 reflecting the increased use of more efficient refineries in Edmonton. Deliveries of light crude were consequently reduced by 5 000 m^3/d to about 14 000 m^3/d, while those of heavy crude remained relatively low at about 500 m^3/d.

Deliveries of refined products from Edmonton to Kamloops were unchanged from the previous year, at around 2 700 m^3/d.

Crude oil deliveries for export by tanker at the Westridge marine terminal averaged 1 200 m^3/d over the third quarter, compared with 1 400 m^3/d in 1988. July and August deliveries were particularly low reflecting the higher demand during the summer months for heavy crudes in eastern Canada and the U.S. mid-west; deliveries during September were at 2 500 m^3/d, similar to those of the second quarter. The ratio of light to heavy crude exports, over the quarter, was about 45:55.

Pipeline exports to the Puget Sound area, at 2 000 m^3/d, were 500 m^3/d higher compared with the third quarter of 1988, as demand by Washington refiners for Canadian light crude remained relatively strong.

Figure 4.1
TMPL Deliveries
000 m^3/d



4.2 Interprovincial Pipe Line Deliveries

Total Interprovincial Pipe Line (IPL) deliveries of crude oil and other hydrocarbons, including petroleum products and natural gas liquids, during the third quarter of 1989, averaged more than 223 000 m^3/d, 7% less than a year ago and 5% less than the previous quarter. The decline is primarily attributable to lower crude oil production.

Apportionment of pipeline space on the IPL system, which had become routine in the last few years, did not occur during the third quarter.

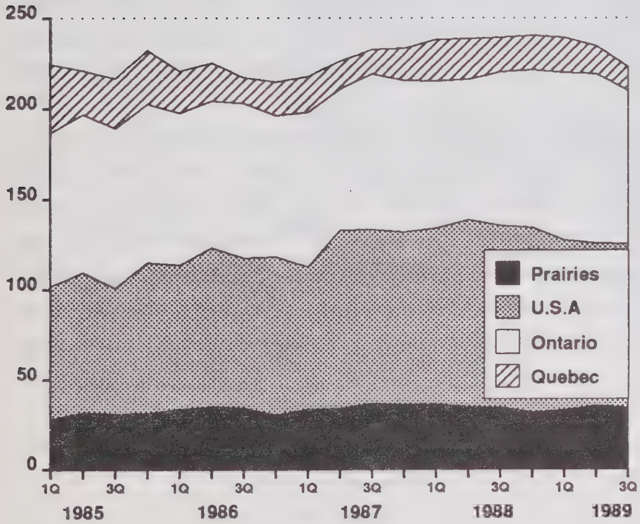
Fifty-nine percent of IPL deliveries were for the domestic market while the remaining 41% were destined for the United States. Compared to the third quarter of 1988, deliveries to the Canadian market decreased by 9% to 132 000 m^3/d, while total exports to the US increased marginally to 91 000 m^3/d.

As a percentage of total IPL deliveries, heavy crude represented about 30% of the mix, similar to previous quarters. Deliveries of conventional light crudes declined to 42%, reflecting lower production.

All regions of Canada received less oil (including natural gas liquids and petroleum products) from IPL during the third quarter, with Ontario registering the most significant decrease, down 10% to 84 000 m^3/d.

Deliveries in the Prairies were down 1 000 m^3/d to 34 000 m^3/d from the second quarter. Operational problems at the Newgrade upgrader reduced the demand for heavy crudes. In Quebec, lower domestic supply combined with foreign crude price advantages (see pricing section) resulted in lower deliveries at 13 500 m^3/d, 40% less than last year and 15% less than in the second quarter.

Figure 4.2
Total IPL Deliveries
000 m^3/d



Outlook for 1990

IPL has decided to delay its proposed 7 000 m^3/d pipeline expansion. The expansion was deferred because recent forecasts indicate that crude oil output in the future would be lower than previously estimated. (See section 3)

Lower deliveries for 1990, forecast to be 213 000 m^3/d, combined with an estimated increase of 10% in the cost of service ($21 million) have prompted IPL to apply to the National Energy Board for a toll increase of about 15%, to be effective on January 1, 1990.

According to the toll application, deliveries to western Canada and Ontario are expected to increase in 1990, while United States and Quebec deliveries would decrease substantially. The following table summarizes the IPL delivery forecast:

Table 4.1
IPL Deliveries of Crude Oil and Equivalent
000 m^3/d

	1989	1990
Prairies	27.7	28.8
Ontario	91.9	97.0
US points	83.2	71.6
Quebec	20.1	15.5
Total	222.9	212.9

4.3 Pipelines to Montreal

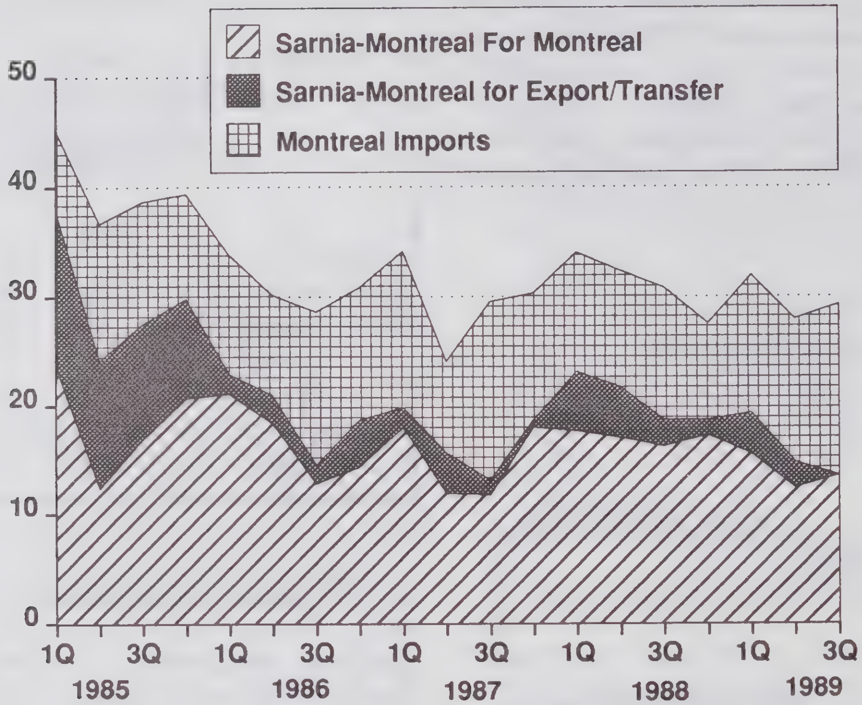
Total pipeline deliveries of crude oil and equivalent to Montreal refiners, during the third quarter of 1989, averaged about 29 000 m^3/d, down 3 000 m^3/d from last year.

Total domestic deliveries via the Sarnia-Montreal portion of the IPL system averaged 13 500 m^3/d, 5 000 m^3/d less than a year ago. Foreign crudes, imported mainly through the Portland Pipe Line, increased by 2 000 m^3/d from last year, to about 16 000 m^3/d.

The steady decline in domestic crude deliveries to Montreal primarily reflects the reduced availability of light crudes from western Canada and the foreign crude price advantage which prevailed in the third quarter.

No exports or domestic transfers from Montreal were reported for the third quarter. This marks the first time in about five years that exports or transfers did not occur. Demand in Canada and the mid-west United States, particularly for heavy crude, appears to have been sufficient to absorb all domestic production, eliminating the need to export heavy crude from the port of Montreal.

Figure 4.3
Crude Oil Deliveries to Montreal
000 m^3/d



5. Exports and Imports

- *Crude oil and equivalent exports declined by 12% as a result of lower production and higher domestic demand.*

- *The trend toward lower exports and higher imports is expected to continue in 1990.*

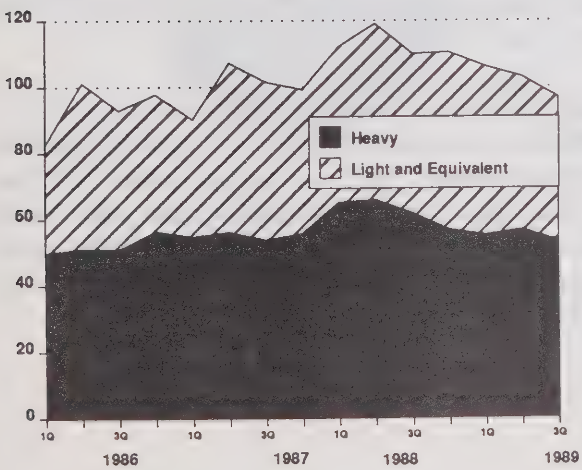
5.1 Crude Oil Exports

For the third consecutive quarter, exports of Canadian crude oil and equivalent declined. Total exports averaged 97 000 m^3/d, 13 000 m^3/d or about 12% less than the third quarter of 1988. As illustrated in figure 5.1.1 exports peaked in the second quarter of 1988.

Export sales were affected by a number of factors, including the decline in light crude oil production, higher domestic consumption of indigenous heavy crude and some IPL pipeline problems in July.

Crude and equivalent exports during the third quarter represented about 36% of domestic production compared with 40% a year earlier. Deliveries were split at a ratio of 55:45 between heavy and light crudes, virtually unchanged from last year. Exports of heavy crudes decreased by 8 000 m^3/d (or 13%) to 54 000 m^3/d, while light crudes fell by 5 000 m^3/d (or 10%) to 43 000 m^3/d.

Figure 5.1.1
Crude Oil Exports
(Third Quarter)
000 m^3/d



As illustrated by table 5.1, all Canadian crude oil exports during the third quarter (based on two months of data),were to the United States. Most of the decline in exports was registered in PAD District II. Third quarter receipts, representing over three quarters of all Canadian exports, averaged 74 000 m^3/d, down 10 000 m^3/d (or 12%) from the same period last year.

The decline in availability of Canadian feedstocks also affected those export markets where producer netbacks were the lowest. No sales to PAD District III or offshore markets were reported. The largest relative decline in receipts was recorded in PAD District I where receipts fell by 35% mainly as a result of a drop in heavy crude deliveries.

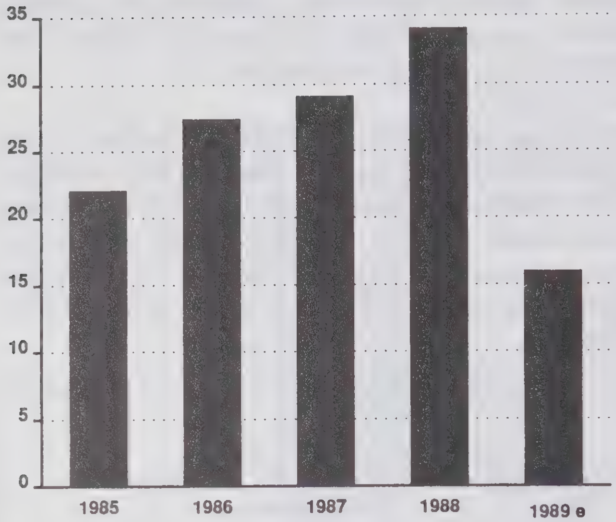
Table 5.1
Crude Oil Exports by Destination
(Third Quarter)
(000 m^3/d)

U.S. PAD Districts	Light 1988	Light 1989	Heavy 1988	Heavy 1989	Total 1988	Total 1989*
I	7.7	6.4	4.1	1.2	11.8	7.6
II	29.6	25.0	53.8	48.6	83.4	73.6
III	0	0	0	0	0	0
IV	8.2	10.7	3.9	3.1	12.1	13.8
V	1.4	1.1	0	0.6	1.4	1.7
Total U.S.	46.9	43.2	61.8	53.5	108.7	96.7
Offshore	1.2	0	0.2	0	1.4	0
Total	48.1	43.2	62.0	53.5	110.1	96.7

* *based on two months data*

As a consequence of the drop in exports and an increase in imports, Canada's net crude oil export position during the third quarter of 1989 declined. Exports of crude exceeded imports by 34 000 m^3/d in the third quarter of 1988. By the third quarter of 1989 the difference had narrowed by about half, to 16 000 m^3/d.

Figure 5.1.2
Net Crude Oil Export Position
(Third Quarter)
000 m^3/d



Based on company nominations, fourth quarter crude oil exports could fall to about 93 000 m^3/d, 15% below the same period last year. Both light and heavy crude exports are forecast to decline. Light crude exports, reflecting the forecast drop in conventional supply, are expected to decrease to 42 000 m^3/d. Heavy crude exports, reflecting both a small increase in production and an offsetting jump in domestic demand, are expected to fall to 51 000 m^3/d.

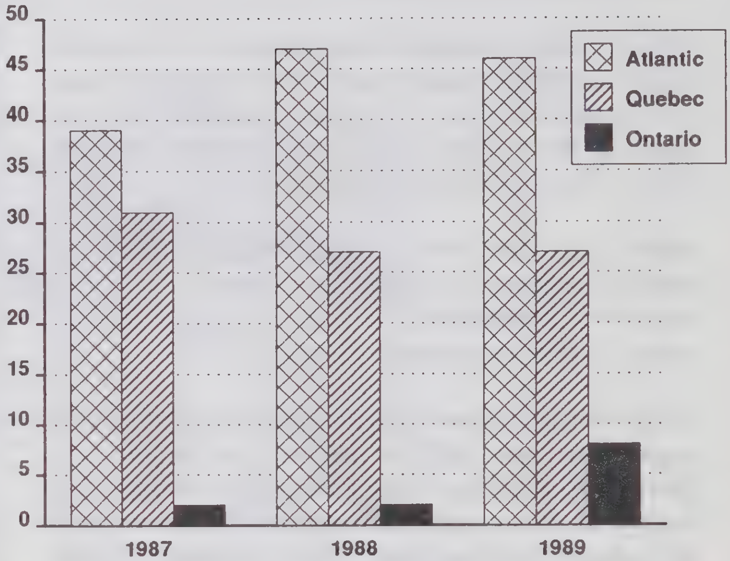
Exports to the United States and offshore markets for the year 1989 are expected to be at least 12% below 1988. This decline has mainly been as a result of lower Canadian production and higher domestic refiner demand. With declining crude oil production in the United States, U.S. refiner demand for Canadian crude remains strong.

Refinery acquisitions in the U.S. by foreign state-owned oil companies attempting to secure markets for their crudes through greater vertical integration are also likely to affect Canadian export markets. For example, the Venezuelan purchase of 50% of Unocal's Lemont, Illinois refinery has resulted in the replacement of over 10 000 m^3/d of Canadian heavy crudes with Venezuelan feedstocks at that refinery (beginning in the fourth quarter of 1989) .

5.2 Crude Oil Imports

Canadian refiners imported 80 000 m^3/d of foreign crude during the third quarter 1989, an increase of 4 000 m^3/d (5%) over the same period a year earlier.

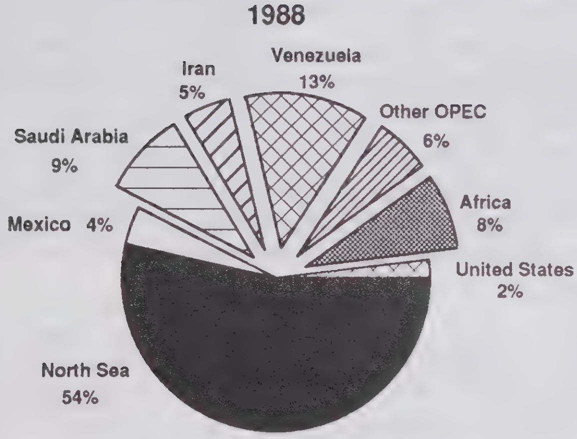
Figure 5.2.1.
Crude Oil Imports By Region
(Third Quarter)
000 m^3/d



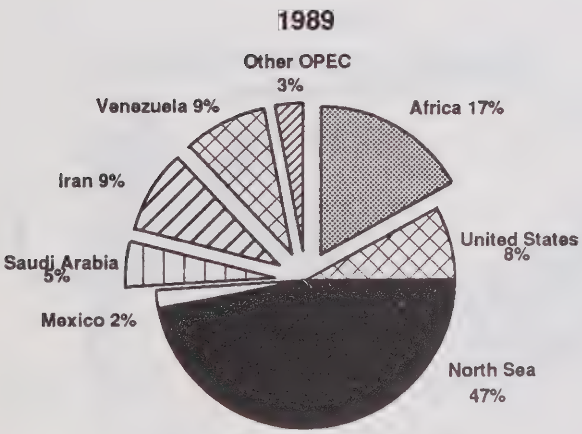
All of the increase occurred in Ontario, where imports more than quadrupled to 8 000 m^3/d, as refiners sought to replace domestic conventional light crude production. Three quarters of the imports were from the United States; however, for the first time since the IPL system was reconnected with the U.S. mid-continent pipeline system offshore crudes, from the North Sea and Africa, were imported into Ontario.

Imports from OPEC countries increased by 11% to 34 000 m^3/d, to represent a 43% share of total Canadian import requirements, up 2 percentage points from last year. The only increases were in African and Iranian imports, which more than doubled. North Sea crude accounted for 47% of all foreign crude receipts, down from last year.

Figure 5.2.2
Sources Of Crude Oil



76 000 m^3/d



80 000 m^3/d

According to Canadian refiners' submissions in October, crude imports are programmed to increase about 10% in 1990, to 84 000 m^3/d, with more than two thirds of the increase expected to occur in the Atlantic region. Much of the Atlantic rise is expected to go to the product export market. Substitution of imports for domestic crude in Ontario and Quebec is forecast to continue as Canadian conventional light crude production declines. Ontario imports are forecast at 5 000 m^3/d, or about 6% of total feedstocks requirements. This compares with about 3% of requirements in 1988.

5.3 Petroleum Products

On a year-over-year basis there was little change in the level of petroleum product exports or imports. More than half of the 35 000 m^3/d of exports were from the Atlantic region. On the import side, product deliveries into Canada were slightly higher than in the third quarter of 1988; however they continue to be substantially above the levels of 1986 and 1987. As outlined in section 1, strong heavy fuel oil demand, primarily for thermal electricity generation, has pushed up product imports since the beginning of 1988.

6. Energy Trade

- *While there were shifts in certain commodities the energy trade surplus remained unchanged from a year ago.*
- *Despite lower volumes, the value of crude exports rose because of higher prices.*

6.1 International

On a customs basis, Canada recorded a trade surplus of almost $600 million in its merchandise account in the third quarter of 1989. A $900 million trade deficit recorded in non-energy related commodities was more than offset by a $1.5 billion energy trade surplus. This surplus was virtually identical to that recorded in the third quarter of 1988 as both the value of imports and exports rose by approximately a quarter of a billion dollars from last year.

Crude oil accounted for a third of the total value of energy exports and half the value of imports. Despite declining export volumes and a somewhat higher Canadian dollar, crude oil export earnings rose almost 15% from last year as a consequence of higher world prices. The fall in the volume of exports reflected the sharp decline in conventional light sweet crude production.

Table 6.1
Canadian Energy Trade
(Third Quarter 1989)*
$ Can (millions)

	Exports	Imports	Balance
Crude Oil	1095	829	266
Petroleum Products	422	475	-53
Natural Gas	669	-	669
LPG's	119	20	99
Coal and Products	600	226	374
Electricity	207	40	167
Uranium	27	44	-17
	3139	1634	1505

* *Estimated based on two months of data*

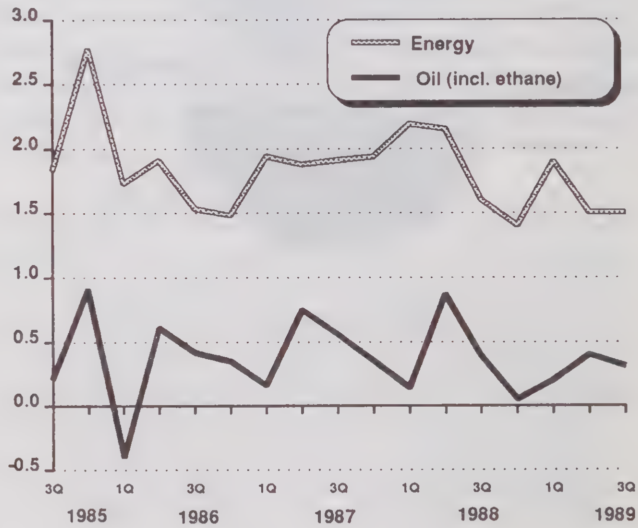
The value of crude oil imports increased by about 20% from last year's level. This also resulted primarily from the decline in domestic crude supply, in conjunction with higher world crude oil prices.

Canada continued to enjoy a substantial surplus in its trade in natural gas and LPGs. In the case of natural gas, the size of the surplus varies directly with the value of exports as there is virtually no natural gas imported into Canada. The 4% increase in this year's natural gas surplus reflected an 8% increase in exports offset by a 4% reduction in export prices. Similarly declines in LPG prices largely nullified the substantial increase in exports, resulting in only a modest improvement in the LPG surplus.

Canada substantially increased the surplus in its coal trade account. With little change in prices, exports were up 40% while imports declined 5%, resulting in a doubling of the surplus over last year.

As a consequence of strong domestic demand, and low water levels which curtailed hydro-electric generation, electricity exports fell while imports climbed resulting in a smaller surplus. Uranium trade also saw a decline in exports and a rise in imports.

Figure 6.1
Oil and Energy Trade Balance
$ CAN (Billions)



6.2 United States

In the third quarter the United States accounted for 80% of the value of Canada's energy exports and a third of its imports. Virtually all Canadian exports of crude oil, refined products, natural gas, LPGs and electricity were destined for the United States. In turn the United States was the source of all electricity, LPG, and coal-related imports into Canada. Whereas Canada accumulated a half a billion dollar deficit in its energy trade with the rest of the world during the quarter, its surplus with the United States approached $2 billion, with the value of its exports being five times higher than that of imports.

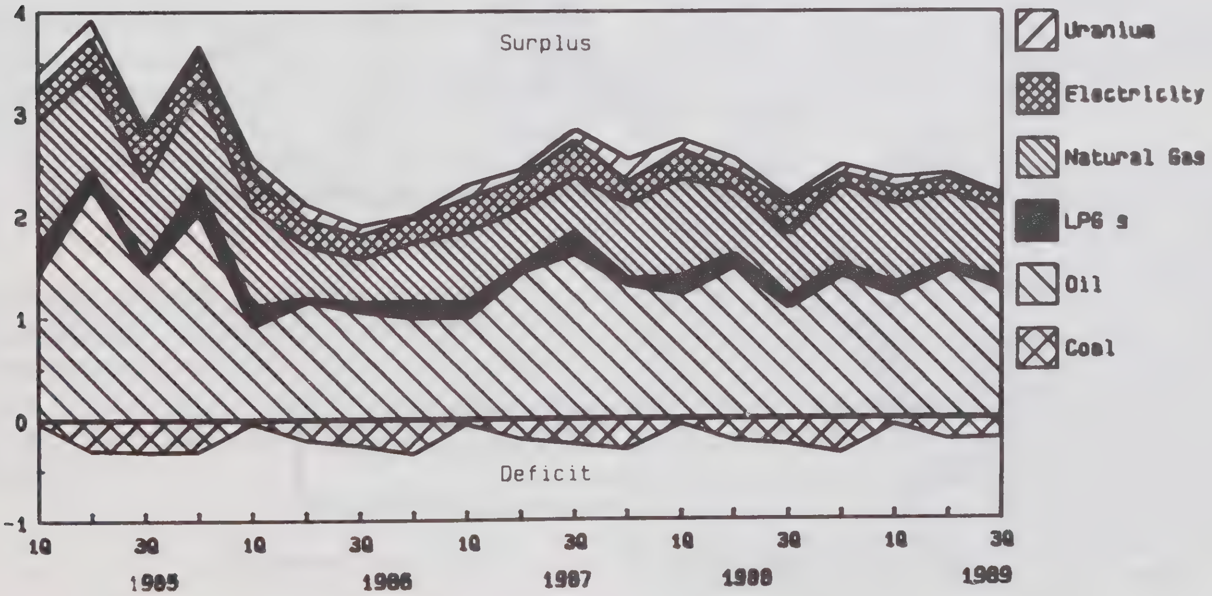
Crude oil exports to the United States declined in the third quarter while imports of U.S. light sweet crudes (into Ontario) rose almost four-fold (although they still only amounted to about 8% of total Canadian crude oil imports volumetrically). Despite these developments, higher crude prices resulted in a higher surplus in the crude oil account, given the substantial net export advantage Canada has with the U.S.

As previously discussed, Canada increased its surpluses in natural gas and LPG trade, while recording a reduction in its electricity surplus. The combination of higher volumes and lower prices of natural gas exports reflected the stiff gas-on-gas competition Canadian producers faced in the U.S. market, in a context of excess productive capacity in the continental natural gas industry. Canadian producers have steadily been expanding their sales in the U.S. by pricing competitively. Natural gas exports could soon level off, however, as exporters come up against pipeline capacity constraints.

Although Canada is overall a net exporter of coal and its products, with its exports going primarily to the Asian Pacific region, it nevertheless continued to run a deficit with the U.S. in coal-related trade in the third quarter.

Figure 6.2

Net Energy Commodity Trade with the United States
$ CAN (Billions)



7. Crude Oil and Product Prices

- *Both crude oil and petroleum product prices were relatively stable throughout the third quarter.*

- *The tightening of the light, sweet crude market in Canada is beginning to have an impact on crude oil posted prices and the relationship between Canadian and American prices.*

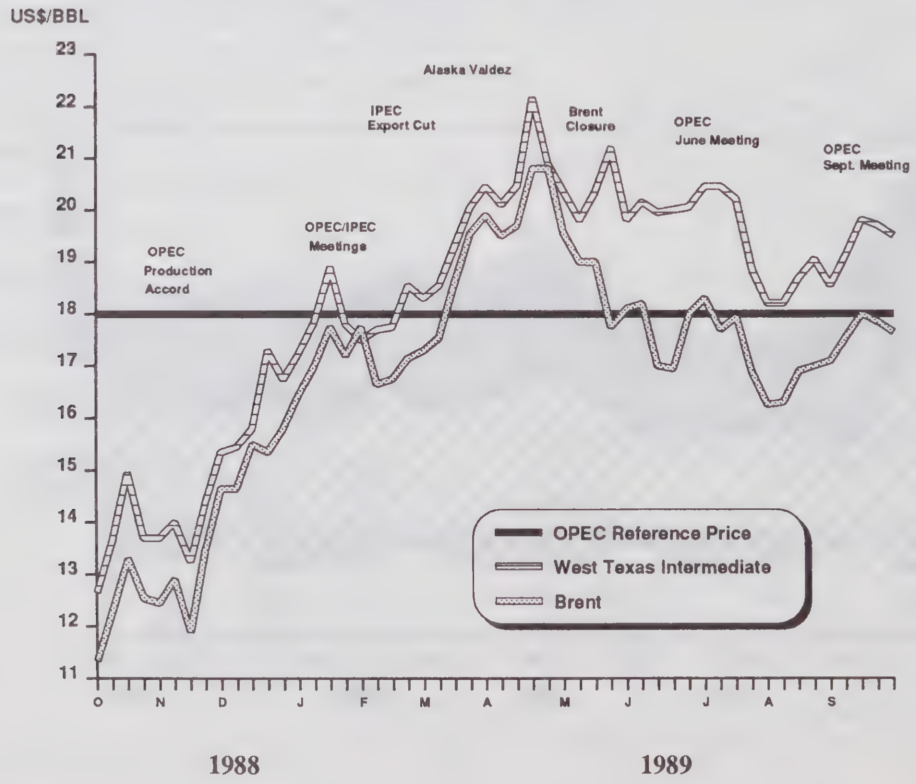
7.1 International Crude Oil Prices

Crude oil prices over the first half of 1989, after reaching levels not seen since 1986, were expected to come under downward price pressure in the third quarter of 1989. However, crude oil prices stabilized in the $18 to $20/bbl range. This price strength basically reflected the ability of world oil markets to absorb the high levels of OPEC crude oil produced in the third quarter (demand was higher than expected).

The third quarter commenced with stable West Texas Intermediate (WTI) prices, primarily reflecting strong motor gasoline demand in the U.S. mid-continent. Continuing supply problems affecting North Sea output (e.g. maintenance work and labour problems), also contributed to firm crude oil prices. WTI averaged $20/bbl during July, maintaining its higher-than-normal price differential over Brent, which averaged $17.70/bbl.

However, in August, market attention focused on OPEC production, which was estimated at over 22 MMB/D, well above its 19.5 MMB/D official ceiling. In addition, the U.K. North Sea was returning to more normal output levels as it recovered from first half curtailments. Consequently, there was a growing market view that the excess production was contributing to a significant inventory build. The result was weaker crude oil prices in August, with WTI declining to $18.55/bbl and Brent to $16.60/bbl.

Figure 7.l.
Crude Oil Prices
$ US/bbl.



September was dominated by OPEC's Market Monitoring Committee meeting, which lasted five days ending September 27. The meeting resolved to increase OPEC's overall production ceiling, on a pro-rata basis, by 1 MMB/D to 20.5 MMB/D. There was also some disagreement among various members over quota reapportionment. Both Kuwait and the UAE objected to their new quotas and have since continued to overproduce. Despite OPEC's inability to resolve the difficult issue of quota re-allocation, the final outcome of the meeting was viewed as positive because OPEC discord was not as prevalent as in previous meetings.

Crude prices strengthened late in the third quarter due to a perception of higher world oil demand and a strong petroleum products market (particularly in the U.S.). The effects of a refinery explosion on the U.S. West Coast and hurricane damage to refineries in the Caribbean also kept petroleum product prices firm. In September, WTI and Brent prices rose to $19.35 and $17.65/bbl, respectively. Over the quarter, WTI averaged $19.30/bbl, down $1.15/bbl from the second quarter average, but up $4.15/bbl over last year's third quarter average price. Brent averaged $17.35/bbl, down $1.55/bbl from the second quarter.

7.2 Domestic Crude Oil Prices

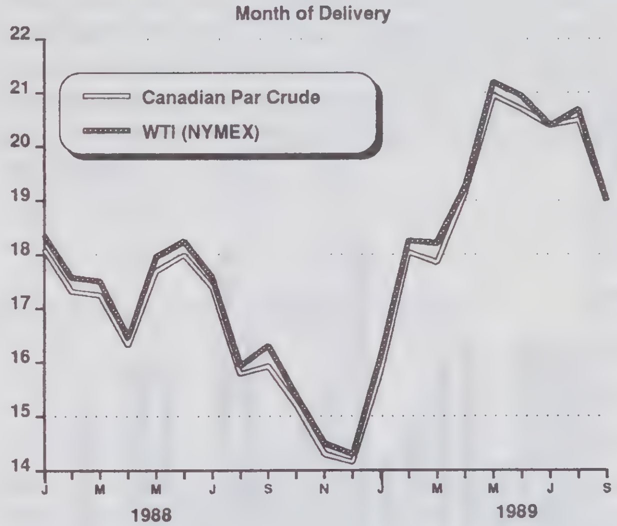
During the third quarter of 1989, Canadian Par crude oil (the Canadian benchmark crude at 40^{o} API, 0.5%S) posted price averaged $21.99 per barrel, a decrease of $1.33 from the second quarter of 1989. The decline reflects an international oil price decrease of about US $1.06 per barrel (equivalent to about CAN $1.46 per barrel).

Canadian light crude oil prices follow the trend set by international crudes, primarily the U.S. benchmark crude West Texas Intermediate (WTI). Figure 7.2.1 illustrates the close relationship between prices for WTI and Canadian Par crude, after adjustments for delivery times to Chicago.

Figure 7.2.1

Canadian Par Crude vs WTI (NYMEX)*

$US/bbl



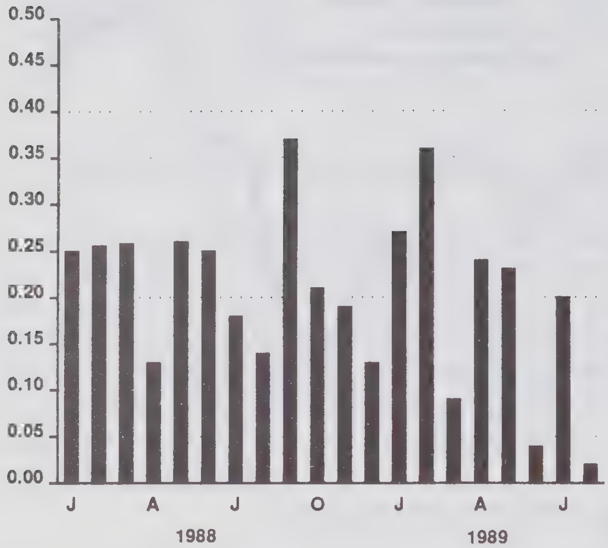
** New York Mercantile Exchange*

The differential between Canadian Par and WTI NYMEX prices, on a delivered basis in Chicago, is illustrated in figure 7.2.2. The average differential in the third quarter of 1989 was US$0.09/bbl, compared to an average of US$0.24/bbl for the first half of 1989. The reduction of this differential can be attributed to a combination of the tightening of light sweet crude supply in North America and the greater dependability of pipeline delivery of Canadian crude to the U.S. market.

In the several years prior to 1989, there was an increase in conventional, light sweet crude production in Alberta as output continued to be higher than expected. All of this "excess" supply was exported to the United States where light crude production was declining. However, since mid-1988 when Canadian light crude production peaked, the North American light, sweet crude market has become tighter. This trend accelerated in the second quarter of 1989 with the further decline in conventional light crude production in Alberta. The changing market conditions appear to be the main factor contributing to the narrowing of the Canadian/WTI differential, as Canadian refiners react to changes in the market when posting their crude oil purchase prices.

Figure 7.2.2

Canadian Par vs WTI (NYMEX)
(Differential at Chicago)
$ US/bbl



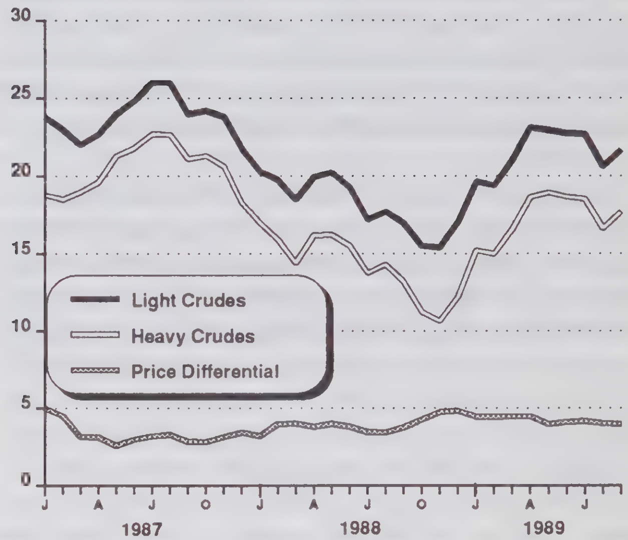
Notes:

Average 1987 -US $ 0.26/bbl
Average 1988 - US $ 0.22/bbl
Average 1st Half 1989 - US $ 0.24/bbl
Average 3Q 1989 - US $ 0.09/bbl

Figure 7.2.3 compares actual prices for Alberta light and heavy crude oil, purchased for use in Canada at main trunk line injection stations. On average, reported light conventional crude oil quality during the third quarter of 1989 was 37.6° API, 0.40% sulphur and blends of heavy crude were 24.0° API, 2.59% sulphur. The differential between Canadian light and heavy crude prices, during the third quarter, was about $4.08 per barrel, $0.11 lower than the second -quarter differential.

Figure 7.2.3

Comparison of Domestic Light and Heavy Crude
(Actual Purchase Prices - Alberta)
$CAN/bbl



7.3 Export Prices

Figures 7.3.1 and 7.3.2 illustrate the relationship between light crude oil export prices and domestic crude prices.

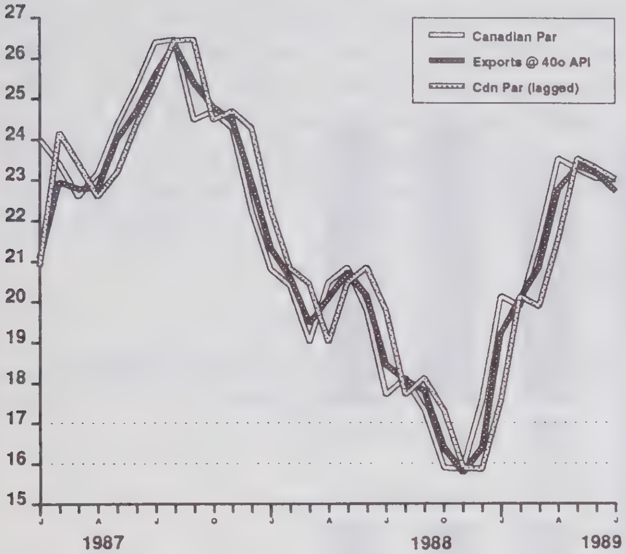
For comparison purposes, prices of light crude oil exported to the United States via the IPL system were netted back to Edmonton and adjusted to 40° API, on a stream-by-stream basis. These prices were then compared to Canadian Par crude prices, also at Edmonton.

In figure 7.3.1, export values include delivery time and Par crude values do not. In a period of declining prices, exports would appear more expensive; and, in a period of increasing prices, exports would appear to be cheaper. An evaluation on that basis alone would be misleading. Canadian Par crude prices were therefore lagged one month in order to normalize for the delivery time factor in the export prices. As can be observed in figure 7.3.1, the average export price falls consistently within the two Par crude curves.

Figure 7.3.1

Light Crude Exports vs Canadian Par

$ CAN/bbl

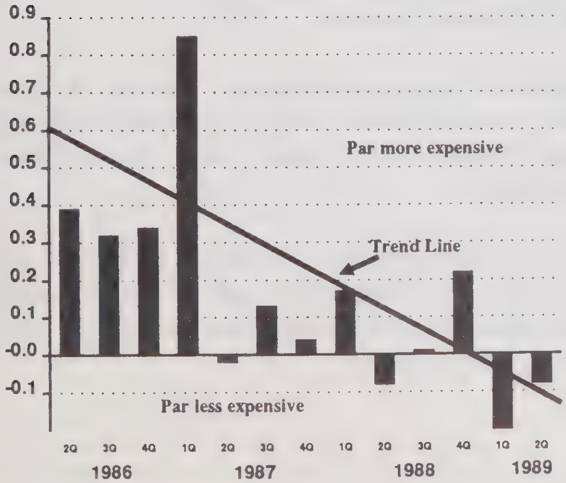


For comparison purposes, an average of the current month's Par crude price and its lagged price was calculated (effectively this assumes a 15-day lag of domestic prices to exports). Figure 7.3.2 illustrates the differential between this composite average Par crude and the average export price. A trend line clearly indicates a contraction of the differential (export price discount) throughout 1987 and 1988. During the first two quarters of 1989, the differential appears to be negative, indicating that export prices, on average, exceeded domestic prices.

Figure 7.3.2

Differential Exports vs Canadian Par

$CAN/bbl



As outlined in section 7.2, ongoing changes in supply/demand balances have affected the relationship between domestic and export prices. Throughout much of 1988 there had been apportionment on the IPL system which contributed to export price discounts relative to Canadian light crude prices. However, the lack of capacity constraints on IPL since April 1989 (there was apportionment in October because of a major pipeline inspection) has contributed to a narrowing/reversal of the differential.

7.4 Petroleum Product Prices

Price Trends

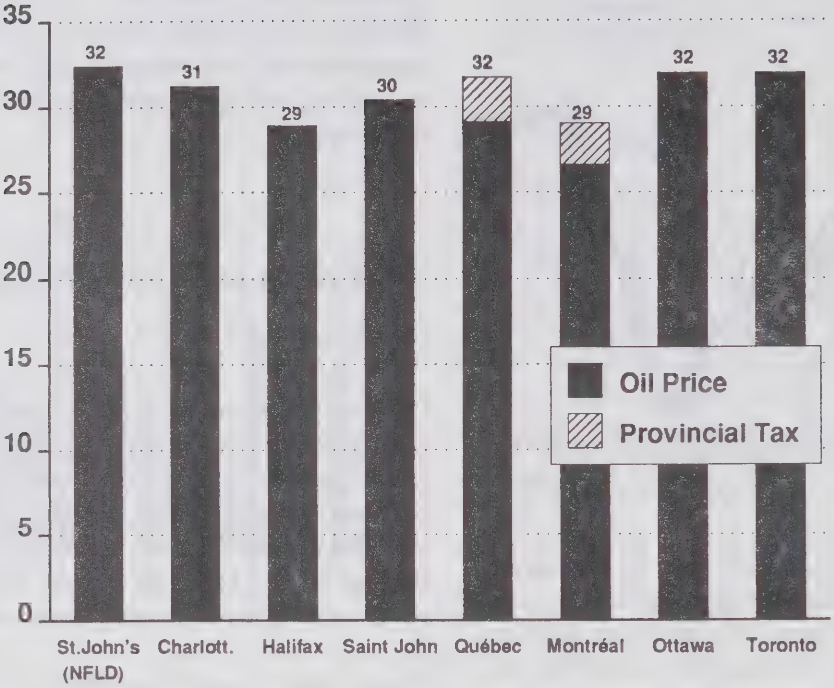
Gasoline prices were remarkably stable during the third quarter. The average Canadian price for regular unleaded gasoline at self-serve outlets was up only 0.5 cents per litre, less than 1% (September 26 vs June 27). However, crude costs and taxes combined increased only 0.1 cent per litre. The balance of the increase was used to cover refining and marketing costs and profits.

Prices were virtually unchanged in Regina, Calgary, Halifax and Montreal. Increases ranged from 0.4 cents per litre in St. John's to 2.6 cents per litre in Charlottetown. Toronto, where prices routinely fluctuated up to 6 cents per litre from week-to-week, was the only city with price war activity. (Appendix III provides a history of prices for ten selected cities).

Retail diesel prices were also fairly stable during the third quarter, up an average 0.4 cents to 49.0 cents per litre. Price changes ranged from a decline of 0.8 cents per litre in Saint John to an increase of 3 cents per litre in Charlottetown.

As the 1989-90 heating season began, average residential furnace prices were up marginally over the close of the 1988-89 season. In September the average price was 30.3 cents per litre, up 0.4 cents per litre since March. Prices changed in each of the ten cities surveyed, ranging from a decline of 0.3 cents per litre in Montreal to a 2.5 cent per litre increase in Halifax.

Figure 7.4.1
Average Consumer Furnace Oil Prices
(September 1989)
cents CAN/litre



Consumption Taxes on Petroleum Products

The federal excise taxes remained unchanged during the third quarter and are currently 8.5 cents per litre on leaded gasoline, 7.5 cents per litre on unleaded gasoline and 4 cents per litre on diesel. (See Appendix IV.)

The federal sales tax on gasoline and diesel is reviewed quarterly and adjusted according to the changes in the Industrial Product Price Index during the previous twelve months. During the third quarter the review process resulted in decreases of 0.9 and 0.7 cents per litre for gasoline and diesel, respectively.

Petroleum product taxes remained the same in four of the provinces and in the Northwest Territories and Yukon. The Newfoundland and Manitoba tax changes resulted from budget changes.

In Newfoundland, the ad valorem rates were increased by 1% to 23% on gasoline and 27% on diesel. In addition, the province imposed a 1.5 cent per litre surcharge on leaded gasoline. Prince Edward Island, Nova Scotia, Quebec, Alberta and the Northwest Territories and Yukon continue to impose identical taxes on leaded and unleaded grades of gasoline.

The Manitoba budget called for a 1 cent per litre tax increase on leaded and unleaded gasolines, currently 10.8 and 9.0 cents per litre respectively. The diesel tax was not changed.

The regular review processes in Prince Edward Island, Nova Scotia, New Brunswick and British Columbia resulted in gasoline and diesel tax increases ranging from 0.1 to 0.9 cents per litre.

Canada vs United States

The average retail price for all grades of motor gasoline increased 0.6 cents per litre in Canada and fell 2.9 cents per litre in the United States during the third quarter of 1989. Lower crude costs, lower refining and marketing costs and profits, and a stronger Canadian dollar accounted for the reduction in the United States. In Canada, a 0.5 cent per litre increase in the refining and marketing costs and profits component accounted for the bulk of the increase.

In September the difference between Canadian and American average gasoline prices was 20.3 cents per litre. Higher consumption taxes in Canada accounted for more than two thirds of the differential. The balance was attributable to higher refining and marketing costs and/or profits in Canada.

Figure 7.4.2

Average Retail Price of Motor Gasoline
(Canada vs United States)
cents per litre

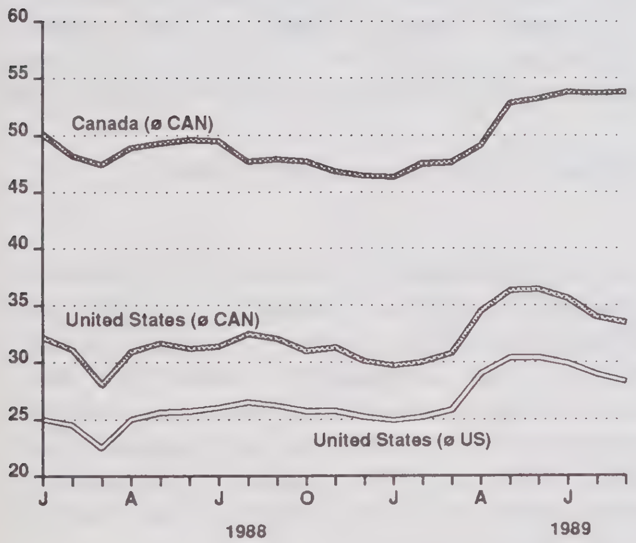
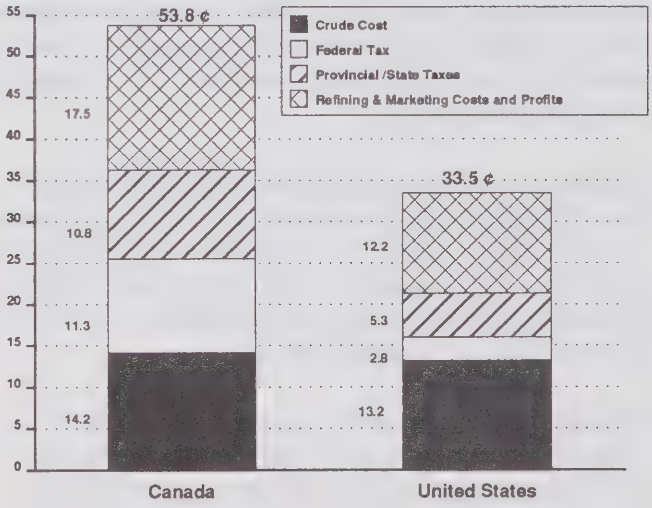


Figure 7.4.3

Breakdown of Average Pump Price
(September 1989)
cents CAN/litre



Exchange Rate = 1.1827

8. Drilling and Exploration Activity

- *More than two thirds of the Canadian drilling fleet remained idle during the third quarter of 1989.*
- *Drilling activity was marked by a significant shift away from oil to the search for natural gas.*

A third-quarter revival of Canadian drilling activity failed to materialize, as more than two thirds of Canada's drilling fleet remained idle. As illustrated by figure 8.1, drilling activity was about 50% less than a year earlier, although last year's level was higher than normal as the industry took advantage of certain drilling incentives which were scheduled to be reduced early in the following quarter.

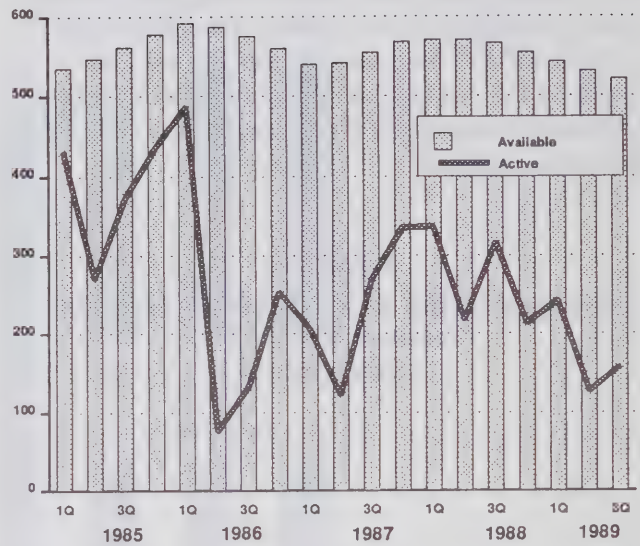
The impact of a strong dollar and high interest rates on the industry debt is reported to have forced many companies to rationalize operations and cut budgets. As well, shifts of property ownership contributed to the overall "drag" in drilling activity.

Despite the fact that the total size of the fleet fell by 49 rigs to 521 (the number of available rigs has fallen in each of the last five quarters), third-quarter rig utilization registered 31% compared with 57% a year earlier. Drilling activity averaged 159 active rigs compared with 322 rigs during the same period last year.

The low point in the quarter was recorded during the last week of August when only 138 rigs were reported active, for a utilization rate of 26%. The lowest point of the year was registered in early May when the rate bottomed-out at 16%.

On a provincial basis, both Alberta and Saskatchewan continued to experience cutbacks in activity. Marginal economics appears to have led to a "retrenchment" in the development of the in situ oil sands and heavy oil fields. Alberta reported a third-quarter average of 112 active rigs, compared with 249 rigs a year earlier, yielding utilization rates of 28% and 55% respectively. Saskatchewan registered 15 active rigs for a 35% rate.

Figure 8.1
Drilling Rig Activity *
number of rigs



* *defined as rigs drilling, rigging or moving*

In the first nine months of 1989 about 4000 exploratory and development wells were completed, about 40% less than the corresponding period last year. This decrease in activity was also accompanied by a marked shift away from oil drilling to the search for natural gas. Oil represented about 40% of completed wells (excluding dry wells) compared with 67% a year earlier. In fact, this is the first time since 1982 that there have been more gas wells completed than oil.

Normally, the fourth quarter produces a high level of interest in drilling as sites are made more accessible by winter freeze-up. Preliminary data for the fourth quarter indicates some renewed interest; however, there are signs that operators are still concerned about the volatility of oil prices and may well delay drilling programs until next year.

The outlook for 1990 is more optimistic, as "vigorous" demand for natural gas is expected to stimulate renewed interest in exploration and development. The search for oil may take longer to recover as companies divert resources into the search for natural gas. As well, conventional oilfields are proving to be increasingly costly to find and develop.

Some analysts and industry officials suggest that an "historic shift" in the Canadian oil industry may now be taking place. Large multinational companies appear to be slowly abandoning the search for costly conventional oil in western Canada. Companies are reported to be moving outside the country (eg. South East Asia, West Africa and the Middle East) where oil exploration and production costs are cheaper and where there is a better chance of major oil discoveries. Analysts predict the trend towards foreign exploration will continue over the next decade.

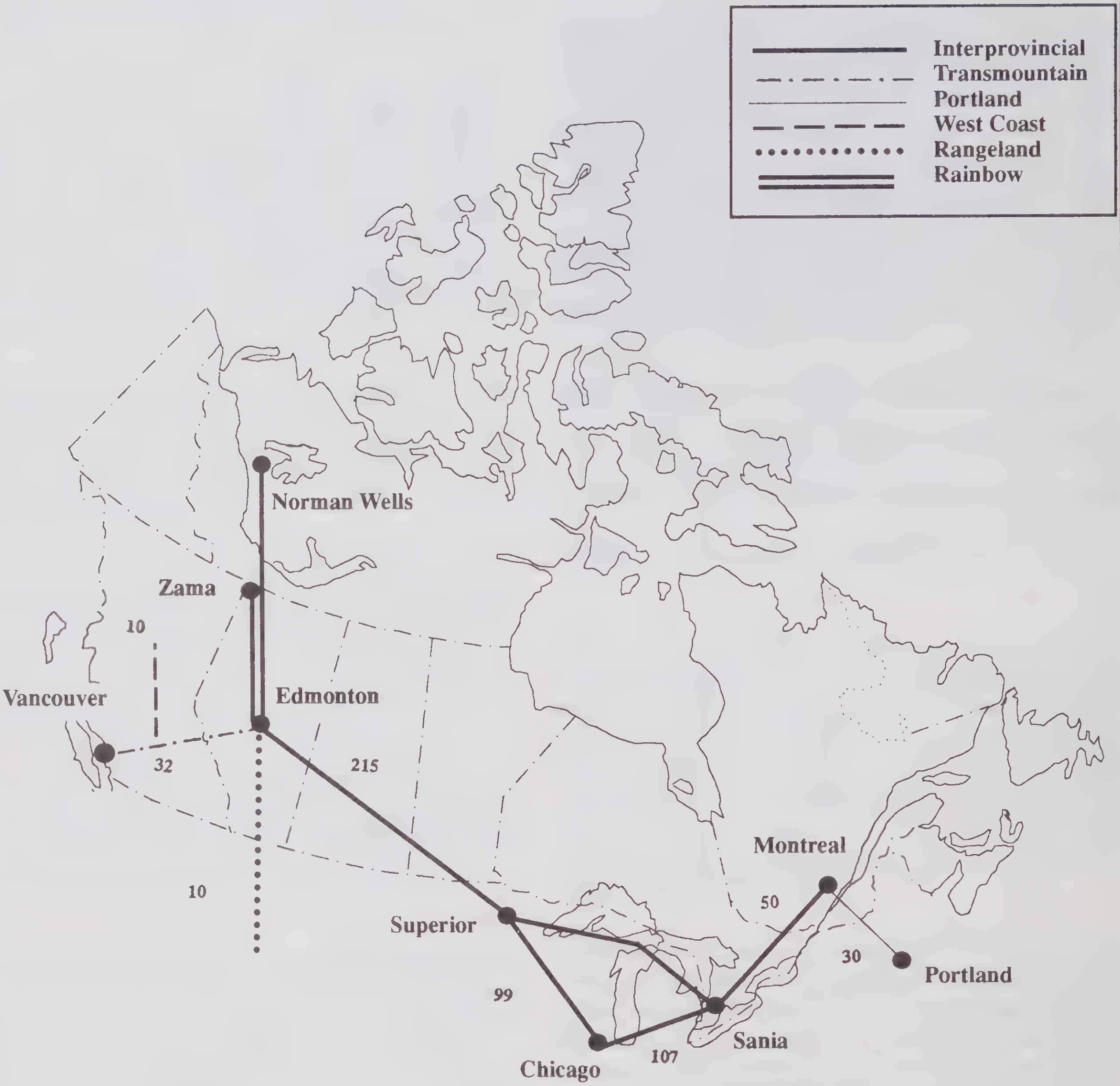
As outlined in section 3, the overall reduction in oil drilling activity has already contributed to lower oil production estimates. The industry has revised downward its forecast of oil output for 1989 and 1990.

Appendix I

Major Crude Oil Pipelines in Canada

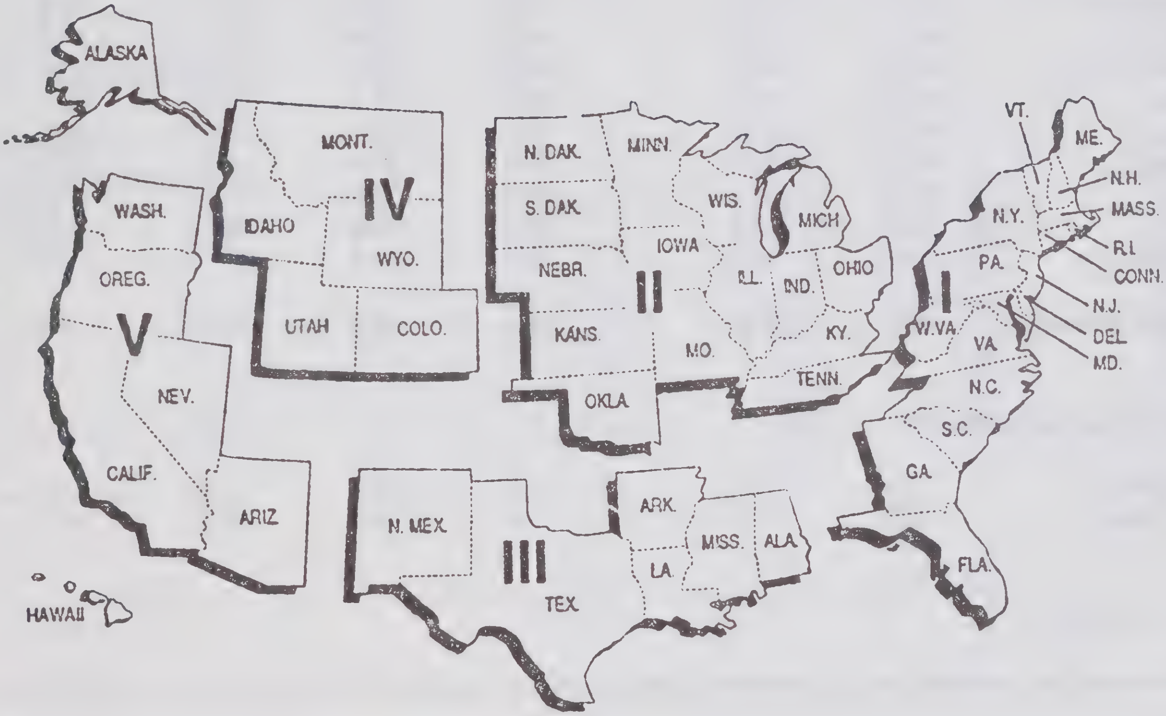
Location and Estimated Capacities

000 m^3/d



Appendix II

U.S. Petroleum Administration for Defense (PAD) Districts



Appendix III

Average Regular Unleaded Gasoline Prices

Self-Serve

1988-1989

	-------1988-------		----------------1989--------------			%
	Sept. 27	**Dec. 27**	**March 28**	**June 27**	**Sept. 26**	**Change 12 mo.**
	----- cents per litre -----					
St. John's(NFLD)	52.5	50.9	52.2	56.3	56.7	8.0
Charlottetown	50.9	49.6	49.6	51.5	54.1	6.3
Halifax *	49.5	47.9	48.8	52.4	52.4	5.9
Saint John(N.B.)*	49.8	48.6	50.2	53.3	53.9	8.2
Montreal	55.8	54.0	55.0	58.1	58.1	4.1
Toronto	46.5	45.9	48.5	50.1	51.3	10.3
Winnipeg	45.9	44.5	43.9	50.9	51.4	12.0
Regina	45.6	39.2	43.3	53.9	53.8	18.0
Calgary	41.6	37.0	41.4	48.2	48.1	15.6
Vancouver	48.8	47.3	49.5	53.6	54.1	10.9
Canadian Average	**49.3**	**47.6**	**49.5**	**53.1**	**53.6**	**8.7**
Consumption taxes included:						
Federal	9.9	9.9	9.8	11.1	11.0	11.1
Provincial	9.9	9.8	9.8	10.4	10.5	6.1

* *Full-serve*

Appendix IV

Consumption Taxes on Petroleum Products

(September 5, 1989)

	Ad valorem		Gasoline			
	Mogas	Diesel	Reg L	Reg UL	Prem UL	Diesel
	(%)		(cents per litre)			
FEDERAL TAXES						
Sales			3.47*	3.47*	3.58*	2.70*
Excise			8.5	7.5	7.5	4.0
PROVINCIAL TAXES						
Newfoundland [a]	23[b]*	27	12.2*	10.7*	10.7*	12.3*
Prince Edward Island	20	23	9.1*	9.1*	9.1*	9.3*
Nova Scotia	20	21	9.0*	9.0*	9.0*	8.8
New Brunswick	24.5[c]	31.5	12.4*	10.4*	10.9*	11.4
Quebec [d]			14.4	14.4	14.4	12.45
Ontario			13.3	10.3	10.3	10.9
Manitoba			10.8*	9.0*	9.0*	9.9
Saskatchewan			12.0	10.0	10.0	10.0
Alberta			5.0	5.0	5.0	5.0
British Columbia [c]	22.5 [f]		10.28*	8.28*	8.28*	8.72*
Yukon			4.2	4.2	4.2	5.2
Northwest Territorie	17	(g)	8.1	8.1	8.1	6.9

(a) *The gasoline tax is reduced by 1.5 cents per litre in the region between the Quebec border and Red Bay in Labrador.*

(b) *This applies to unleaded gasoline. The tax on leaded gasoline is l.5 cents per litre higher than the unleaded tax.*

(c) *This applies to all gasolines. There is also a 2.2 cent per litre surcharge on regular leaded gasoline.*

(d) *Reduced by varying amounts in certain remote areas and within 20 kilometers of the provincial and U.S. borders.*

(e) *Additional transit tax of 3.0 cents per litre in Vancouver.*

(f) *This applies to unleaded gasoline. Taxes on leaded gasoline and diesel fuel 2.0 and 0.44 cents per litre higher, respectively, than the unleaded tax.*

(g) *85% of gasoline tax.*

** Changed since last quarter.*

Glossary

Bitumen	A naturally occurring viscous mixture composed mainly of hydrocarbons heavier than pentane, which may contain sulphur compounds and which in its natural state is not recoverable at a commercial rate through a well.
Conventional area	Those areas of Canada that have a long history of hydrocarbon production. Conventional areas are also referred to as nonfrontier areas.
Crude oil and equivalent	Includes crude oil, synthetic crude, oil produced from oil sands plants, and condensate.
Feedstock	Raw material supplied to a refinery or petrochemical plant.
Heavy crude oil	Loosely applied, crude oils with a low API gravity (high density).
In situ recovery	With reference to oil sands deposits, the use of techniques to recover bitumen without the necessity of mining the sands.
Light crude oil	Crude oil with a high API gravity (low density). Generally includes all crude oil and equivalent hydrocarbons not included under heavy crude oil.
Natural gas liquids	Those hydrocarbon components recovered from raw natural gas as liquids by processing through extraction plants, or recovered from field separations, scrubbers or other gathering facilities. Includes the hydrocarbon components ethane, propane, butane and pentanes plus, or a combination thereof.
Oil sands	Deposits of sands and other rock aggregate that contain bitumen.
Pentanes plus	Also referred to as condensate. A volatile hydrocarbon liquid composed primarily of pentanes and heavier hydrocarbons. Generally a by-product obtained from the production and processing of natural gas.
Productive capacity	The estimated production level that could be achieved, unrestricted by demand, but restricted by reservoir performance, well density and well capacity, oil sands mining capacity, field processing and pipeline capacity.
Shut-in capacity	The unused production capability of currently producing oil and gas wells plus the total production capability of all shut-in oil and gas wells, regardless of whether or not they are connected to surface gathering and production facilities.
Synthetic crude oil	Crude oil produced treatment in upgrading facilities designed to reduce the viscosity and sulphur content.

The Canadian Oil Market

Vol. V, No. 4, Fourth Quarter 1989

Energy, Mines and Resources Canada
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Canada

THE ENERGY OF OUR RESOURCES

THE POWER OF OUR IDEAS

THE CANADIAN OIL MARKET

Vol. V, No. 4, Fourth Quarter 1989

Canadian Oil Markets and Trade Division
Energy Sector
Energy, Mines and Resources Canada

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Table of Contents

List of Figures

List of Tables

The Canadian Oil Market

Overview

- *Seasonally-adjusted demand for petroleum products recovered somewhat during the fourth quarter, after two consecutive quarters of decline, reaching 239 000 m^3/d. Demand increased by about 4% nationwide in 1989, with Atlantic Canada recording the largest increase, at 10%.*

- *Sales of regular unleaded gasoline rose from a 24% share of total gasoline sales in 1979, to a 65% share in 1989.*

- *Although drilling rig activity in 1989 was at its lowest level in the decade, it is expected to recover in 1990 by 10 to 15%, in anticipation of rising demand for natural gas and stable oil prices.*

- *In 1989, conventional light crude oil production fell 6% or 10 000 m^3/d, reflecting declining reserves and lower exploration and development activity. On the other hand, unblended heavy crude oil supply increased by about 1 000 m^3/d due to higher conventional production in Alberta, particularly in the Bow River area.*

- *Crude oil imports rose over 5 000 m^3/d in 1989. OPEC accounted for 80% of incremental imports as North Sea supplies experienced disruptions.*

- *Crude oil exports declined 9% to 103 000 m^3/d in 1989. With the United States increasing its imports, Canadian crudes accounted for a lower share of total U.S. imports, falling from a 13% share in 1988 to 11% last year.*

- *Refinery utilization rate went up on average by 3% to 86% in 1989, with Ontario recording the largest increase.*

- *Canada saw a decline in its crude oil trade surplus in 1989, the consequence of falling domestic crude oil production and rising domestic crude oil demand. The deterioration in Canada's crude oil trade position would have been substantially greater were it not for higher crude oil prices in 1989.*

- *Price differentials between Canadian crudes and West Texas Intermediate narrowed substantially in 1989, reflecting the tightening of light sweet crude supplies in North America.*

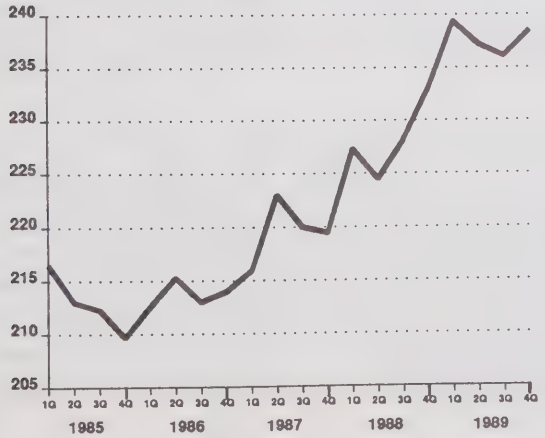
1. Domestic Consumption

- *Seasonally adjusted net sales of petroleum products during the fourth quarter of 1989 were marginally higher than the average of the three previous quarters.*
- *Refined petroleum product consumption in 1989 was up 4% over the previous year.*
- *Regular unleaded gasoline, which accounted for 24% of total gasoline sales in Canada 10 years ago, currently represents about 65% of sales.*

1.1 Fourth Quarter Consumption

Petroleum product consumption (see definition in glossary), in Canada, seasonally adjusted at annual rates during the fourth quarter of 1989 approached 239 000 m^3/d, marginally higher than the average level of the previous three quarters. After peaking at almost 240 000 m^3/d in the first quarter, seasonally adjusted sales declined somewhat during the following two quarters before partially recovering in the fourth. Figure 1.1 illustrates the trend in seasonally adjusted product sales over the 1985-89 period. Whereas there existed a pronounced upward trend in product sales between 1986 and 1988, demand remained relatively flat in 1989, in part reflecting the current economic slowdown and higher product prices.

Figure 1.1
Total Petroleum Product Consumption
(Seasonally Adjusted at Annual Rates)
000 m^3/d

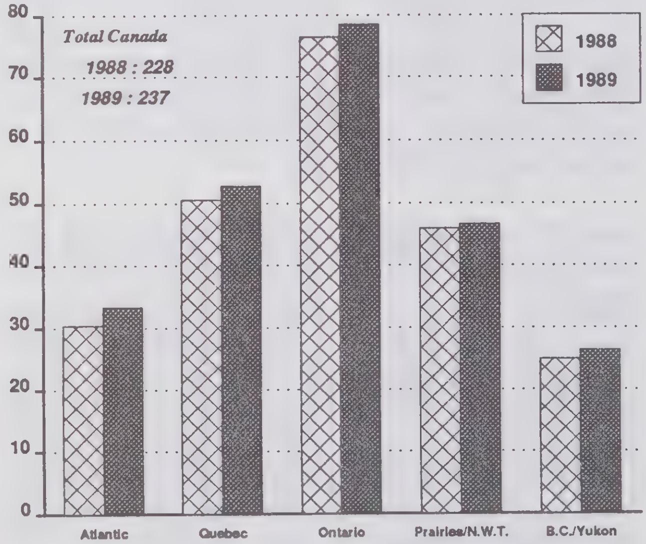


1.2 Consumption in 1989

On an annual basis, sales of refined petroleum products averaged 237 500 m^3/d during 1989, an increase of about 4% or 9 000 m^3/d over the annual 1988 level. On a regional basis, Atlantic Canada recorded the largest increase in consumption with sales rising by about 10% largely due to a 25% increase in heavy fuel oil consumption.

Sales of motor gasoline at 95 000 m^3/d, were 2% higher than 1988 levels. Quebec and British Columbia showed increases of about 4% while Ontario gasoline sales grew at the national average. In the Atlantic and the Prairies gasoline consumption remained virtually unchanged. According to Statistics Canada data on the consumption of refined products by sector in 1988, road transportation accounts for about 90% of motor gasoline sales, with the agricultural and commercial sectors making up the balance.

Figure 1.2
Regional Petroleum Product Consumption
000 m^3/d



Led by a 7% increase in Quebec, growth in diesel fuel consumption continued to outpace that of motor gasoline in 1989, rising by 3% to 47 000 m^3/d. Here too the transportation sector accounts for a large share of total diesel consumption: about 60% in 1988. In contrast to gasoline, which is for the most part sold through retail pump outlets, diesel fuel consumption is concentrated in the marine, railway, trucking and urban transit industries. Moreover, whereas gasoline sales are largely confined to the transportation sector, the demand for diesel fuel is more broadly based with significant sales to industrial, commercial and agricultural users.

About two-thirds of light fuel oil (LFO) sales are to the residential sector and another 20% to the commercial sector, by and large for space heating. Almost 90% of heating oil consumption occurs in eastern Canada, natural gas generally being the alternative fuel used in western Canada. Heating oil sales rose 6% in 1989 to over 21 000 m^3/d, largely because of a surge in demand in December when unusually cold weather caused sales to rise 35% in eastern Canada on a year-over-year basis.

Consumption of heavy fuel oil (HFO) rose 20% to 27 000 m^3/d in 1989. HFO, in fact, accounted for almost half the increase in total refined product consumption in 1989. Much of the incremental demand had come from the electric power utilities which in 1988 accounted for over a quarter of HFO consumption. The pulp and paper industry has traditionally been another large consumer, accounting for about 20% of sales or almost half of total industrial demand. About 15% of HFO sales are to the marine transportation industry.

Sales of "other" products increased marginally in 1989 to average 47 000 m^3/d. By volume, about half of "other" products are sold for non-energy purposes, by and large to the industrial sector. Asphalt, petrochemical feedstocks and anode coke (used to refine aluminum) are some of the major non-fuel products in this category. On the other hand, jet fuel and refinery LPGs account for most of the demand for energy-related "other" products. Marginally higher sales of jet fuel and asphalt more than offset lower demand in 1989 for refinery LPGs, petrochemical feedstocks and petroleum coke.

Table 1.2
Refined Product Consumption By Sector
(1988)
% Share

	Mogas	Diesel	LFO	HFO	"Other"
Electricity Generation	-	1	1	28	-
Industrial	-	16	8	51	50
Transportation	91	60	-	16	33
Agriculture	4	9	3	-	1
Residential	-	-	65	1	3
Government	-	4	4	1	4
Commerce	4	9	18	3	9
	100	100	100	100	100

1.3 International Oil Consumption

Consumption of refined products in the OECD countries increased on average by one percent in 1989. Collectively, the three regions shown in Table 1.3 account for over 70% of refined petroleum products sales in the non-communist world.

OECD countries in Europe and the Pacific increased their oil use by 1.3% and 4.8%, respectively. These increases were about 20% lower than those observed in the previous year.

Sales in North America remained steady in 1989. Canadian consumption increased by about 4% whereas there was vitually no change in product demand in the United States.

Table 1.3
Petroleum Product Consumption
% change over previous year

	North America		OECD Europe		OECD Pacific	
	88/87	89/88	88/87	89/88	88/87	89/88
Motor Gasoline	2.5	0.2	3.6	2.2	3.4	5.4
Middle Distillates	6.2	-1.8	0.1	-1.1	9.5	4.2
Heavy Fuel Oil	17.5	-0.3	-1.3	0.6	2.3	2.7
Other products	2.3	0.0	4.3	4.5	5.9	5.1
Total	3.5	-0.2	1.6	1.3	5.8	4.8

Note: 89/88 % change based on 11 months of data.

1.4 Motor Gasoline Trends in the 1980s

General Market Overview

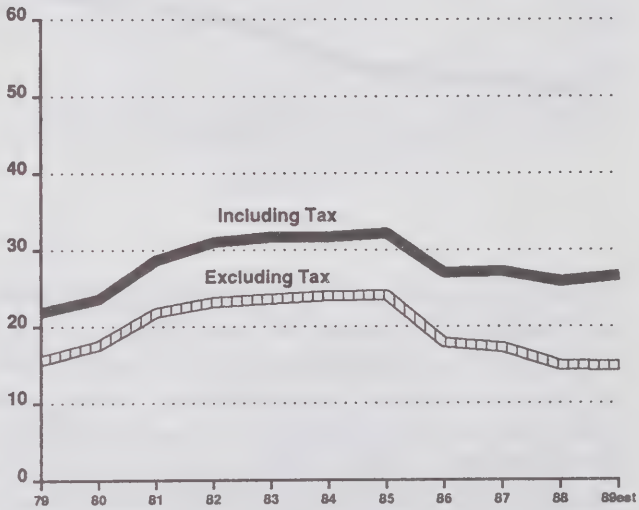
Both the international and domestic oil markets went through major changes in the 1980s. Following the 1979 international oil crisis, there were expectations of continuing high prices and supply shortages. The National Energy Program (NEP) was announced in 1980 under these circumstances. By the mid-1980s, however, the international oil situation had reverted to one of surplus oil supplies and declining prices. A significant decline in oil consumption in the early 1980s was one of the factors contributing to the oil surplus.

In Canada, oil policies were also transformed in the first five years of the decade. Federal government policy moved from an interventionist to one driven by market forces with the deregulation of Canadian crude oil markets in 1985.

During the 1980s, the federal government did not have jurisdiction over the prices of petroleum products. They were priced according to market forces, except in a few provinces where agencies regulated certain aspects of prices. While product prices were affected by crude oil costs, provincial and federal taxes, and refining and marketing costs and profits, it was the marketplace and competition which dictated oil product prices in the short term.

Despite the changes that occurred in Canada and the world during the 1980s, real gasoline prices in Canada rose at an annual average rate of less than 2%. On a tax-excluded basis, real prices actually declined during the decade. The consumer spent a smaller proportion of personal expenditures on motor fuels in 1989 than in 1979.

Figure 1.4.1
Canada Average
Regular Leaded Gasoline Prices
Cents/l (1979 $)



Changes in Market Structure

Self-serve outlets accounted for an increasing share of the outlet population throughout the 1979-89 period, although the trend has levelled off in recent years. By 1989, 41% of the stations in 10 major centres were self-serve. The number of stations which converted to self-serve varied considerably among the regions, as illustrated below.

Figure 1.4.2
Self-Serve Outlets vs Total
By Region (%)

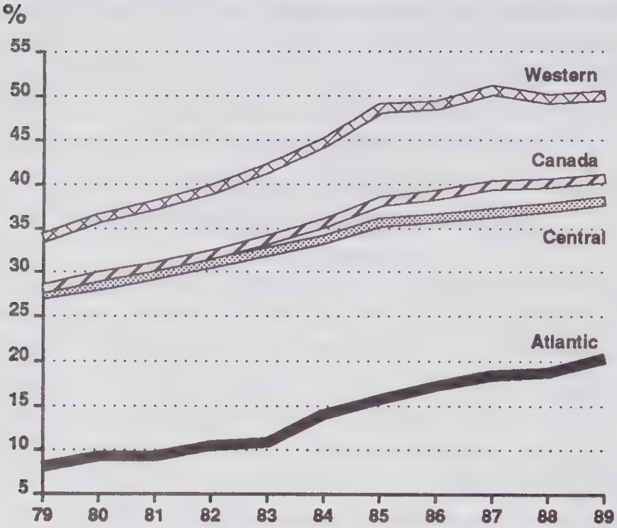
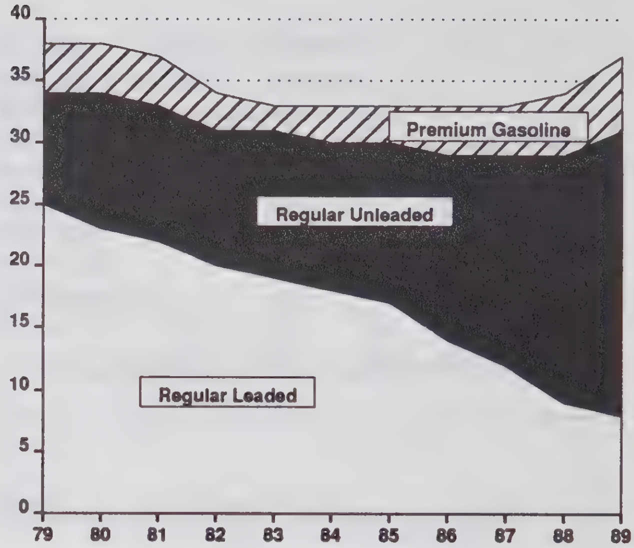


Figure 1.4.3
Market Share of the Three Grades of Gasoline
Volume of Sales (Millions of m^3)



Two of the three centres in the Atlantic region, Saint John and Halifax, do not allow self-serve outlets. St. John's on the other hand has the highest percentage share (65%) of self-serve stations of the 10 major centres. The Central region includes Montreal, Ottawa and Toronto while Winnipeg, Regina, Edmonton and Vancouver are included in the Western region. By 1989 half of Western outlets were self-serve, while just under 40% of central Canada's stations and about 20% of Atlantic Canada's outlets had been converted.

One of the more dramatic changes in the retail gasoline market during the 1980s was the switch to unleaded fuels. In 1979 regular unleaded gasoline accounted for 24% of total gasoline sales in Canada. By the end of the decade, this share had grown to 65%, with an 8% increase in 1989 alone. Much of the 1989 shift can be attributed to higher taxes on leaded fuels. The federal sales tax and consumption taxes in several provinces were increased on leaded fuels during the year to reduce price differentials between leaded and unleaded gasoline.

A review of price trends and consumption taxes can be found in Section 8.5 of this quarterly. To obtain copies of the complete report **"Canadian Motor Gasoline Markets -1980s The Decade in Review"**, call (613) 992-8770 or (613) 992-0602.

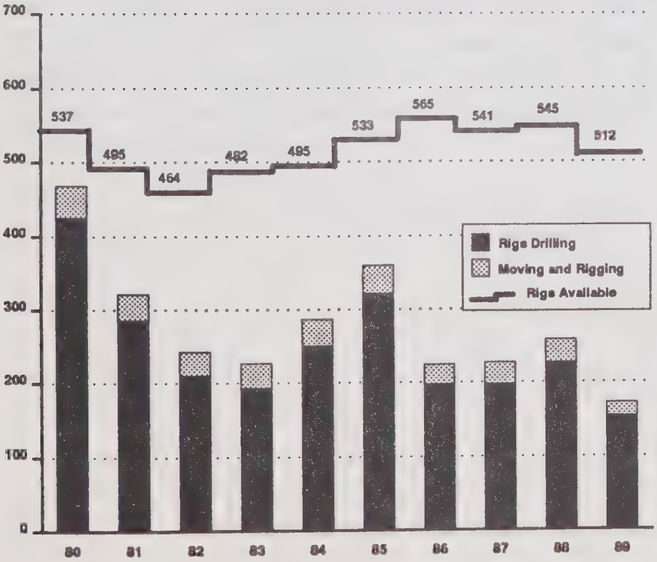
2. Drilling and Exploration Activity

- *Fewer wells were drilled in 1989 than in any other year since 1975.*
- *Drilling expenditures are expected to increase by 10 to 15% in 1990 as a result of rising demand for natural gas and stable oil prices.*

1989 proved to be one of the worst years on record for the Canadian drilling industry. In western Canada only 30% of available rigs were reported as drilling, compared with 41% in 1988. Equally significant, the average size of the 1989 drilling fleet, compared with 1988, fell by 33 rigs or 6% to 512.

The Canadian Association of Oilwell Drilling Contractors (CAODC) states that the industry requires a 50% to 55% drilling utilization rate to meet costs and a 60% to 65% rate to realize a profit. As illustrated by figure 2.1, the drilling industry's experience over the last four years was below 45%.

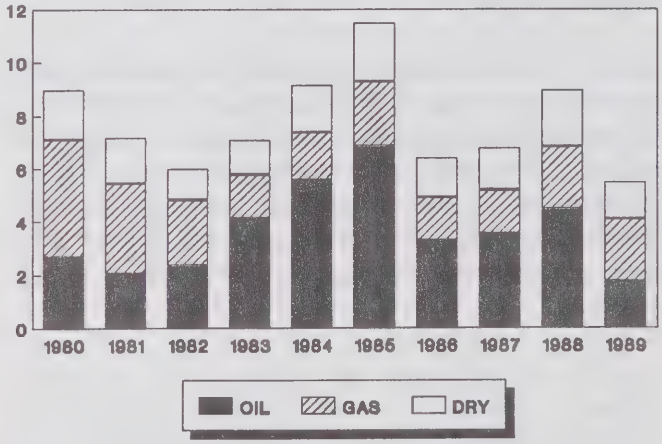
Figure 2.1
Drilling Activity in Western Canada
(number of rigs)



The drilling slump was largely caused by slashed company exploration budgets in the wake of the 1988 oil price collapse. As well, the impact of a strong dollar and high interest rates on industry debt forced many companies to rationalize operations and cut budgets. The year was also characterized by company mergers and acquisitions which redirected spending away from drilling programs to asset management.

Fewer wells were drilled in 1989 than in any other year since 1975. Well completions totalled 5454, 39% less than in 1988. As illustrated by figure 2.2, the decline was more severe for oil drilling which fell to 1724 completions, 61% less than the year before. Gas completions totalled 2327, only 3% less than last year and, for the first time since 1982, there were more gas wells drilled than oil.

Figure 2.2
Well Completions
(in thousands)



However, after a dismal 1989, CAODC cautiously predicts a steady growth in drilling activity through to the mid-1990's. Pushed by rising demand for natural gas and stable oil prices, the association forecasts a 10% to 15% increase in 1990, for an average drilling rate of about 35%. For the first quarter of the year, traditionally the busiest period, CAODC predicts a 53% utilization rate, 15% higher than the same period in 1989. A 30% drilling rate is expected for the remainder of the year.

The drilling sector is reported to be somewhat encouraged by forecasts of increased exploration and development spending. CAODC suggests that 1990 drilling expenditures will increase by 15% to $2.5 billion, compared with 1989.

The industry also welcomed revisions to Alberta's Royalty Tax Credit Program (ARTC), designed to make it easier for the industry, especially small producers, to raise financing for oil and gas drilling projects. The revamped program should encourage drilling by removing the element of fiscal uncertainty that is thought to have held back investment.

The ARTC (effective January 1,1990) was renewed for a five-year term instead of the one-year terms under which the old program operated. Companies will recover rebates, applied equally to all companies, of up to 85% on the first $2.5 million in oil and gas royalties payable per year, compared with 75% on a cap of $3 million under the previous program. The percentage of royalties recoverable drops as oil prices rise above $US 15/bbl. When the price increases to $US 25/bbl the ARTC rate falls to 30% and remains at that level no matter how high the price rises.

Analysts note that the termination the Canadian Exploration and Development Incentive Program (CEDIP), the Canadian Exploration Incentive Program (CEIP) and various provincial tax royalty holidays, for the most part, mark the end of direct government grants to the industry. These programs, born with the price collapse of 1986, were meant to ease the impact of lower prices on the industry.

3. Crude Oil Supply

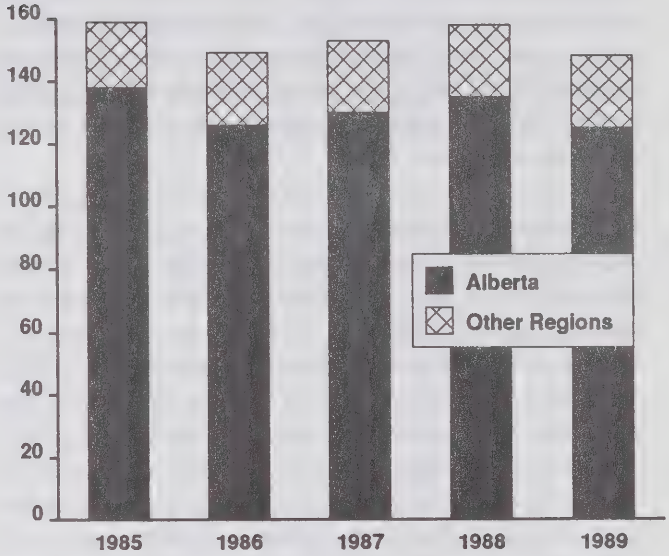
- *Crude oil production in 1989 averaged 266 000 m^3/d, 3% less than the previous year.*
- *Crude oil imports increased by 5 000 m^3/d to 77 000 m^3/d in 1989.*
- *Total supply (domestic crude plus imports) available for delivery was 344 000 m^3/d.*

3.1 Domestic Crude Oil Production in 1989

Based on estimates from the National Energy Board (NEB), total crude oil and equivalent production in Canada (including Ontario) averaged 266 000 m^3/d in 1989. This represented a decline of almost 3% or 7 000 m^3/d from the level of output achieved in 1988 when production reached its highest level of the decade.

Conventional light crude oil production fell 6% or 10 000 m^3/d, to 148 000 m^3/d. The fall off in the conventional sector, virtually all of it in Alberta, signalled a resumption of the gradual decline in the productive capacity of the older established oil fields, which had been observed prior to 1987 (see figure 3.1.1). In 1987 and 1988 more development drilling in the established fields temporarily raised their productivity. This higher infill drilling in turn reflected higher crude oil prices (specifically in 1987) and the introduction of a number of temporary government incentive programs and royalty holidays designed to promote exploration and development (E&D).

Figure 3.1.1
Conventional Light Crude Oil Production
000 m^3/d



However, the dramatic fall in crude oil prices towards the end of 1988, in conjunction with the phasing out of some drilling incentives, had the effect of sharply curtailing both exploratory and development drilling last year. Although crude oil prices had quickly recovered by early 1989 and had remained relatively steady throughout the year, the gyrations in crude oil prices seen in the previous three years had by then created a climate of uncertainty about the direction crude oil prices would take. Rather than commit significant financial resources to E&D in 1989, many producers in the conventional sector cautiously adopted a "wait and see" attitude. The consequence of this was that the incremental production coming on stream from fewer new discoveries failed to replace falling production in the existing fields, inevitably leading to declines in both production and productive capacity in the conventional sector.

Despite a downward revision in productive capacity in August, the average level of light crude oil shut-in, at 5 000 m^3/d, was nonetheless more than double that recorded in 1988. However, last year's level appears to have been overestimated. Pipeline capacity constraints may have caused shut-in during the first quarter; however, the high levels of shut-in recorded during the second and third quarters may be partly illusory given the apparent absence of pipeline constraints and the strong demand for light crude during this period.

Partially offsetting the decline in conventional light crude oil production was higher synthetic crude supply. Synthetic production rose 1 000 m^3/d from the year before to approach 33 000 m^3/d in 1989. Suncor production levels remained at or near capacity for most of the year. At 9 000 m^3/d in 1989, production was about 1 000 m^3/d higher than in 1988 when first quarter production was adversely affected by a major fire at the plant in late 1987.

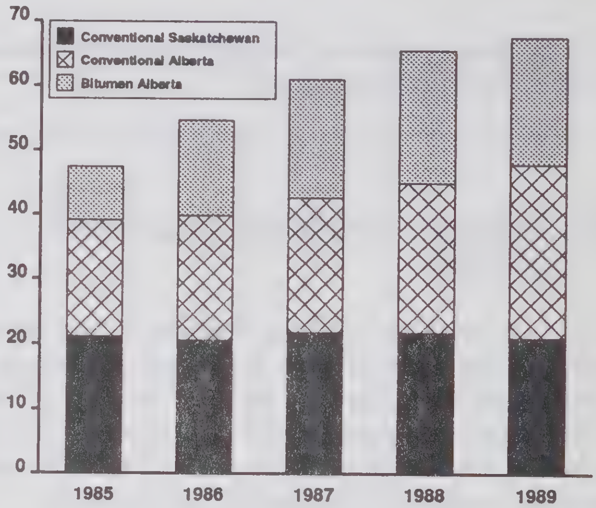
Production at Syncrude, at close to 24 000 m^3/d, remained virtually unchanged from 1988. This was in spite of the fact that peak capacity at Syncrude had been raised by about 3 000 m^3/d following the completion of its Capacity Addition Program in the fall of 1988. Syncrude was plagued by a series of production problems over the course of the year which, in combination, were of sufficient magnitude to negate the positive impact of the capacity expansion. Early in 1989, operations were disrupted by mechanical problems associated with the plant's gas oil hydrotreater facilities. Subsequently, production fell below anticipated levels as a result of two prolonged coker turnarounds in the first and third quarters. Finally, in mid-December, operations were once again disrupted by a major explosion and fire at the plant and a weather-induced shutdown of one of the coker units. The severity of this latest disruption was such that regular production levels are not expected to resume until late in the first quarter of 1990. Despite these problems, Syncrude production reached a record level in May when it peaked at almost 30 000 m^3/d.

Condensate supply in 1989 remained steady at 18 000 m^3/d relative to the previous year. Thus, with significantly lower conventional production, modestly higher synthetic crude supply and steady pentanes plus production last year, net production of light crude oil and equivalent fell 8 000 m^3/d to 199 000 m^3/d from the year before.

Despite a lower overall level of development activity in 1989, total unblended heavy crude oil supply actually increased by over 1 000 m^3/d to 67 000 m^3/d from 1988. The increase was totally attributable to higher conventional production in Alberta, particularly in the Bow River area. Bitumen production declined marginally, reflecting the postponement of several major development projects originally slated for 1989.

Estimated heavy crude oil productive capacity grew by 1 000 m^3/d to 70 000 m^3/d in 1989. The level of shut-in, on the other hand, remained steady at about 3 000 m^3/d.

Figure 3.1.2
Heavy Crude Oil Production
000 m^3/d



3.2 Crude Oil Imports by Source

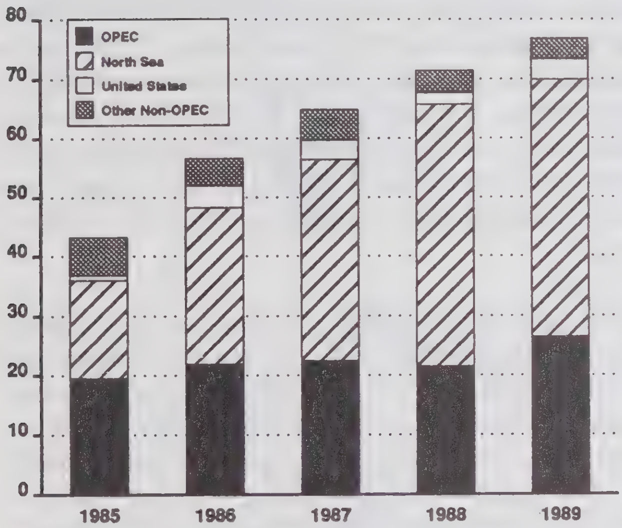
In 1989 total crude oil imports rose by over 5 000 m^3/d from the year before, to average 77 000 m^3/d, with virtually all of the imports delivered to refineries in eastern Canada. The one exception was a February test batch of Alaskan North Slope crude barged to a B.C. refinery.

In part, the increase in crude oil imports into Ontario and Quebec reflected the combination of falling domestic light crude oil supply and rising feedstock requirements by refineries in these regions. The higher foreign crude oil receipts in the Atlantic, on the other hand, reflected the region's strong growth in refined product consumption in 1989 and a sizeable crude oil inventory build over the year.

The North Sea continued to account for the majority of Canadian crude oil imports with a 56% share of the total. As shown in figure 3.2.1, after crude oil market deregulation in 1985, North Sea imports rose steadily through to 1988. These imports declined marginally in 1989 to below 44 000 m^3/d as a result of a series of accidents which temporarily curtailed North Sea supply earlier in the year.

The rise in North Sea imports over the course of the last five years resulted primarily from two developments. First, deregulation ended government-subsidized domestic oil transfers to non-pipeline connected refineries in eastern Canada. These refineries turned to North Sea sources given their relatively close proximity, ready availability and suitable crude quality. Second, North Sea imports were further boosted by certain Atlantic refinery processing arrangements, designed to process imported crude for re-export as product.

Figure 3.2.1
Imports of Crude Oil by Source
000 m^3/d



Higher OPEC deliveries more than helped offset the small decline in North Sea receipts in 1989. OPEC imports approached 28 000 m^3/d, an increase of 4 000 m^3/d from 1988, with most of the increment coming from Nigeria, Canada's largest single supplier of OPEC crude. After declining from a 45% share of total imports in 1985 to 30% in 1988, OPEC's market share recovered somewhat in 1989 to 35%, reflecting North Sea production problems.

Although U.S. crudes account for a relatively small share of total Canadian imports, they nonetheless comprise most of the imports into Ontario. In 1989, these U.S. imports grew by about 70% to 3 500 m^3/d, with most of the increase occurring in the second and third quarters, when a sudden fall-off in domestic light sweet crude supply (both conventional and synthetic) occurred in conjunction with strong seasonal product demand, particularly for gasoline. Also, some domestic light crude deliveries, originally destined for Ontario, were diverted to the Consumers' Co-op refinery to compensate for the commissioning problems at the Newgrade heavy crude oil upgrader in Regina.

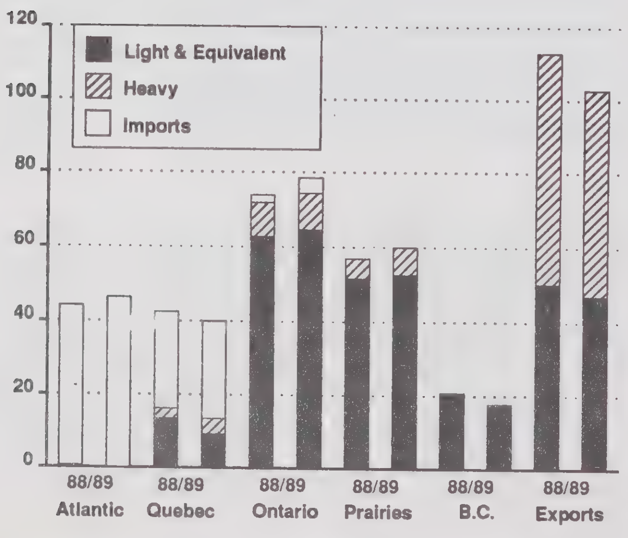
With Canadian crude oil supply (including Ontario production and recycled diluent) estimated to have averaged 267 000 m^3/d in 1989, and crude imports 77 000 m^3/d, the total available supply of crude oil in Canada last year amounted to about 344 000 m^3/d. About 30% of this crude oil supply was exported, with the remainder going to domestic refiners.

4. Crude Oil Disposition

- *Deliveries of crude oil to Canadian refineries increased by 2% to 243 000 m^3/d in 1989.*
- *Exports of crude oil averaged 103 000 m^3/d in 1989, 9% less than in 1988.*

Reflecting a higher level of demand in Canada for refined petroleum products, total crude oil receipts by domestic refineries (excluding receipts of both gas plant butanes and partially processed oil) rose in 1989 by almost 5 000 m^3/d, or 2%, from the year before to 243 000 m^3/d. Nevertheless, receipts of domestic crude oil actually fell by about 1 000 m^3/d to 166 000 m^3/d, a consequence of the significant decline in the indigenous supply of conventional light crude oil. Total domestic light and equivalent receipts fell nearly 5 000 m^3/d to 144 000 m^3/d. This decline however, was largely offset by a 4 000 m^3/d increase in domestic heavy crude oil deliveries. Eastern refiners also relied more on foreign crudes to meet their feedstock requirements, increasing imports in 1989 by more than 5 000 m^3/d to 77 000 m^3/d. The figure below shows the disposition of crude oil available in Canada (both domestic crude oil and imports) during the 1988-89 period.

Figure 4.1
Disposition of Crude Oil
000 m^3/d



4.1 Canadian Refinery Crude Oil Receipts

The Atlantic region's four refineries increased their combined crude receipts, virtually all imports, by about 5% to 46 000 m^3/d, reflecting strong regional demand for refined products and a 1 000 m^3/d build in crude oil inventory levels over the year. Since deregulation in 1985 these refineries have doubled their crude receipts largely as a result of certain processing agreements, whereby crude oil is imported, refined and re-exported as product.

In 1989, the three Quebec refineries reduced their crude receipts by about 5% to 40 000 m^3/d from the year before. In 1985, Quebec receipts averaged close to 45 000 m^3/d. The following year these receipts fell to 40 000 m^3/d and have remained relatively steady since. However, a gradual change in the sourcing of crude receipts has occurred over the last 5 years. In 1985, domestic crude oil accounted for slightly over half of total crude receipts in Quebec, with imports making up the balance. By 1989, Canadian crudes accounted for only a third of receipts.

Total crude oil deliveries to Ontario's seven refineries approached 79 000 m^3/d in 1989, up 6% from the year before. Over the 1985-89 period, Ontario receipts remained remarkably stable, rising by only 2% overall during this period. An unanticipated reduction in domestic light crude oil deliveries during the second and third quarters of 1989 resulted in significantly higher crude oil imports into Ontario. Imports, mostly from the U.S., reached 8 000 m^3/d during the third quarter before falling back to below 3 000 m^3/d in the final quarter. The consequence was a near doubling of Ontario crude imports to 4 000 m^3/d in 1989 from the year before.

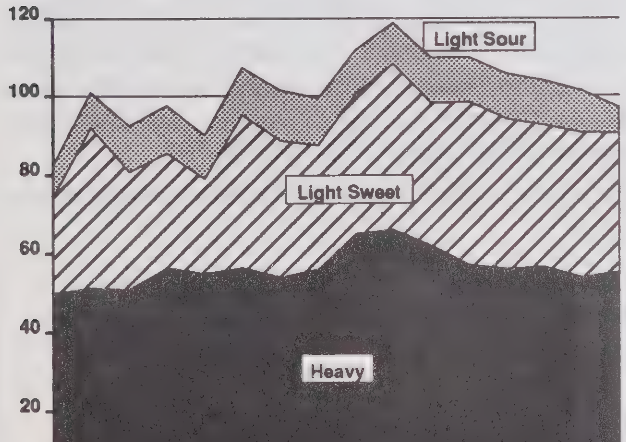
The Prairie region's nine refineries increased their crude oil receipts by 5% to 60 000 m^3/d in 1989. Since 1985, the total growth in receipts has been about 12% or almost 7 000 m^3/d. Most of this increase is attributable to rising transfers of partially processed oil from Edmonton to Vancouver-area refineries. The majors have, in recent years, shifted some of their refinery operations to Edmonton from Vancouver in order to take advantage of economies of scale. In 1989 alone, these transfers surpassed 5 500 m^3/d, almost double the rate recorded in 1988.

Concomitantly, these transfers have led to a reduction in light crude oil deliveries to B.C.'s six refineries. B.C. crude oil receipts in 1989 dropped by 15% to 18 000 m^3/d from the year before, and by 20% since 1985.

4.2 Canadian Crude Oil Exports

Total crude oil exports for 1989 averaged 103 000 m^3/d, 9% less than the year before. This drop was the result of a number of factors, most importantly, the decline in domestic conventional light crude production and higher domestic consumption of indigenous heavy crudes. Fourth quarter exports at 100 000 m^3/d, were slightly below the previous quarter, and almost 10% below the same period a year earlier.

Figure 4.2.1
Crude Oil Exports
000 m^3/d



Crude and equivalent exports, during 1989 represented about 39% of total Canadian production, compared with 41% the previous year. Exports were split at a ratio of about 55:45 between heavy and light crudes, virtually unchanged from 1988. Heavy crude exports fell by 11% to 56 000 m^3/d (71% of blended heavy crude supply) and light crude exports decreased by 7% to 47 000 m^3/d (25% of net light crude production). Light sweet crudes represented about 80% of total light crude exports, unchanged from last year.

As illustrated by Table 4.2, almost all of Canadian crude oil exports, during the fourth quarter of 1989, were delivered to the United States with small volumes tankered via the ports of Montreal and Vancouver to offshore destinations. Exports to U.S. PAD District II (PADD), the major market for Canadian crude oil, accounted for about three quarters of Canada's total exports. (See Appendix I).

Canada's share of the total U.S. crude oil import market has been on the decline since early 1988. According to American Petroleum Institute and National Energy Board data, Canada's import market share in 1989 fell to about 11% from 13% the year before. Nevertheless, Canada remains the fourth largest source of crude oil imports behind Saudi Arabia (18%) Nigeria (13%) and Mexico (12%).

Most of the decline in Canadian crude oil exports was registered in U.S. PADD II , which comprises the Twin Cities and Chicago refining areas. Fourth quarter deliveries, representing about 45% of the PADD II import requirements averaged 75 000 m^3/d, 12% less than the same period last year. Most of the decrease was the result of a significant drop in light crude oil deliveries. The lower supply of Canadian light crude appears to have been a factor behind the reduction.

Canada's market share of PADD II import requirements, for both heavy and light crudes, fell in 1989. Deliveries of Canadian heavy crude oil, as illustrated by Figure 4.2.2, accounted for about 75% of all heavy crude imports, down four percentage points from 1988. About 25% of PADD II light crude oil imports (Figure 4.2.3), were met by Canadian supplies, down from 37% in the previous year.

Figure 4.2.2
Heavy Crude Oil Imports
Into PAD District II
000 m^3/d

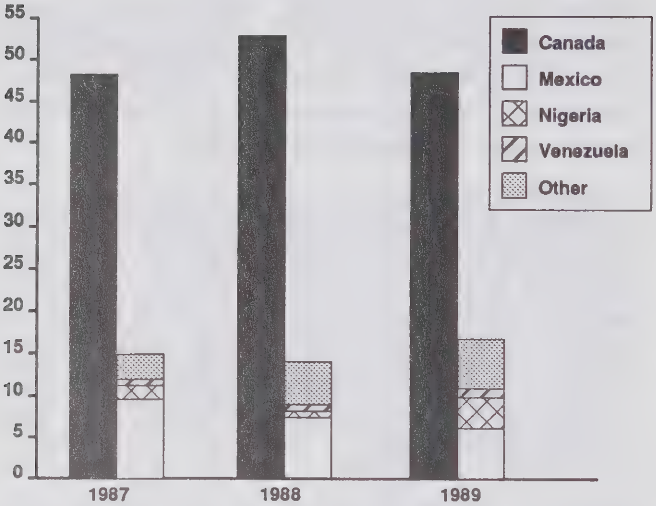
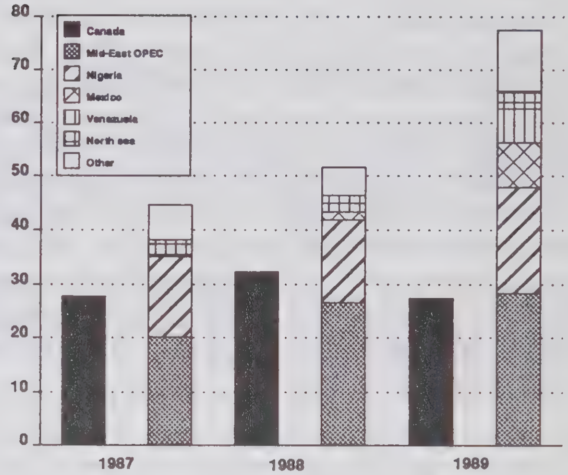


Figure 4.2.3
Light Crude Oil Imports
Into PAD District II
000 m^3/d



While PADD II registered the largest drop in fourth quarter deliveries, most other PADD destinations, with the exception of PADD V, registered only small decreases in volume. Exports to Canada's second largest export market, PADD IV, the Montana and Wyoming refining areas, remained at about 10 000 m^3/d.

Crude oil exports for 1990, based on refiners' submissions to the National Energy Board, are forecast to fall to 99 000 m^3/d, almost 4% below the 1989 average. Light crude exports, reflecting the forecast drop in conventional supply, are expected to decrease to 41 000 m^3/d, 12% below the 1989 average. However, heavy crude exports, reflecting a small increase in supply, are expected to increase by 3% to about 58 000 m^3/d.

Table 4.2
Crude Exports by Destination
(Fourth Quarter)
000 m^3/d

U.S PAD Districts	Light 1988	Light 1989	Heavy 1988	Heavy 1989	Total 1988	Total 1989	% share of U.S. Imports 1988	% share of U.S. Imports 1989
I	9.3	7.5	0.5	1.2	9.8	8.7	5	4
II	33.9	24.5	50.8	50.0	84.7	74.5	51	45
III	0	0	1.3	1.2	1.3	1.2	-	-
IV	8.1	8.9	2.8	1.5	10.9	10.4	100	100
V	1.9	2.5	0.4	0.4	2.3	2.9	7	6
Total U.S.	53.2	43.4	55.8	54.3	109.0	97.7	13	9
Offshore	0	0	1.4	2.5	1.4	2.5	-	-
Total	53.2	43.4	57.2	56.8	110.4	100.2	-	-

5. Pipelines

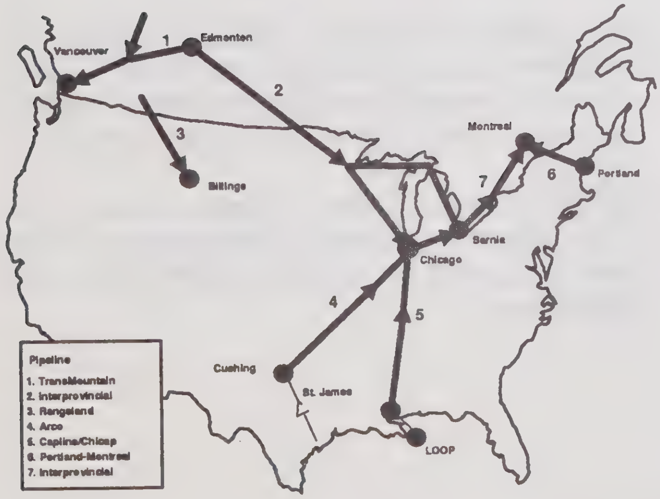
- *Both IPL and Trans Mountain throughput declined in 1989, a consequence of falling domestic crude oil production.*

- *Reflecting higher foreign crude oil receipts by Montreal refiners, Portland Pipeline deliveries rose by about 2 500 m^3/d last year.*

Western Canadian crude oil is delivered to markets through a network of pipelines. A map illustrating major crude oil pipelines in North America is shown below.

The Trans Mountain Pipe Line and the Interprovincial Pipe Line originate in Edmonton, where most Canadian crude oil is gathered. The Rangeland pipeline supplies U.S. refiners south of the Prairie provinces. The selected American pipelines shown on the map illustrate the supply alternatives for our main export market. Chicago can be supplied with US domestic crudes from Cushing, Oklahoma, with foreign crudes through the US Gulf, and with Canadian crudes via the Interprovincial pipeline.

Major Crude Oil Pipelines In North America



5.1 Trans Mountain Pipe Line

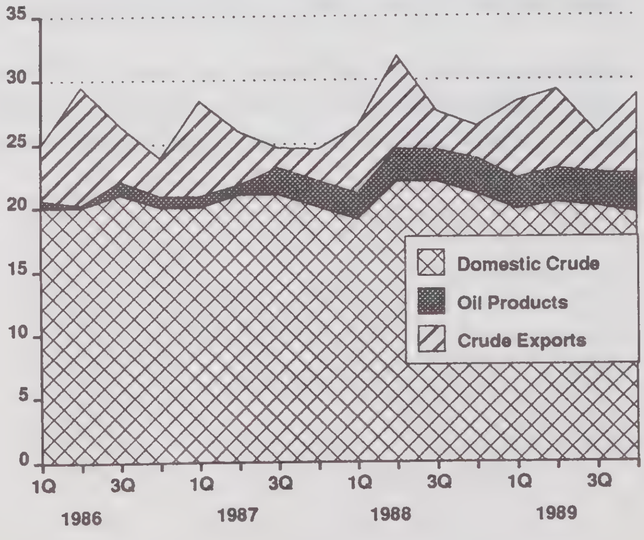
During the fourth quarter of 1989, Trans Mountain Pipe Line (TMPL) throughput averaged 28 800 m^3/d, up 11% from the previous quarter. The average throughput for the year was 28 000 m^3/d, down marginally from the previous year. Although the company completed a capacity expansion towards the end of 1989, the throughput for 1990 is expected to remain virtually unchanged.

Total deliveries of crude oil to B.C. refineries in 1989 were 14 500 m^3/d, 3 000 m^3/d lower than in 1988. However, deliveries of semi-refined products grew by 2 500 m^3/d to 5 500 m^3/d, reflecting the increased use of more efficient refineries in Edmonton. Deliveries of refined products from Edmonton to Kamloops, B.C. increased by more than 200 m^3/d to 2500 m^3/d in 1989.

Crude oil deliveries for export, either at the Westridge marine terminal or Puget Sound, averaged about 5 400 m^3/d in 1989, 500 m^3/d more than the previous year. In fact, tanker exports decreased by 700 m^3/d while pipeline exports increased by 1 200 m^3/d.

Trans Mountain Pipe Line reduced its tariffs by about 5 percent, on November 16, 1989. The basic toll applying to deliveries of light crude oil from Edmonton to Burnaby, B.C. declined from \$6.72/m^3 to \$6.39/m^3. An application for an increase in 1990 has since been filed with the National Energy Board.

Figure 5.1
Trans Mountain Deliveries
000 m^3/d



5.2 Interprovincial Pipe Line

The Interprovincial Pipe Line (IPL) system is composed of two segments, the first one is in Canada and is referred to as IPL while the second, called "Lakehead", serves American markets in the Great Lakes area.

Total IPL and Lakehead deliveries of crude oil and other hydrocarbons, including petroleum products and natural gas liquids, during the fourth quarter of 1989, were 229 000 m^3/d. The average throughput for the year exceeded 231 000 m^3/d, down 4%, or almost 10 000 m^3/d, from 1988.

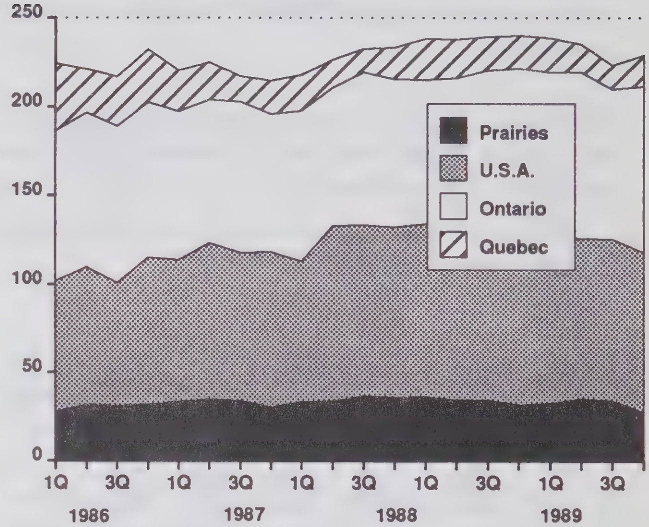
In contrast to 1988, when pipeline capacity constraints frequently forced the imposition of pipeline space allocation among shippers, apportionment was only required in the first quarter of 1989 and, again, in October.

Total deliveries of crude oil to Canadian refineries in 1989 were 140 000 m^3/d, 1 000 m^3/d higher than in 1988. These deliveries represented 60% of IPL throughput. Deliveries to the United States were 91 500 m^3/d, down about 10 000 m^3/d from the previous year.

In July 1989, IPL increased its tolls. The pipeline cost of delivering light crude oil to Toronto was raised by \$0.23 to about \$8.15/m^3. An anticipated increase in the cost of service during 1990, combined with a projected decline of about 6 000 m^3/d from actual 1989 deliveries, prompted IPL to apply to the National Energy Board for an upward toll adjustment to be effective early in 1990. If approved, the new tolls would represent an increase of about \$0.60/m^3 from those prevailing since last July.

According to the toll application, deliveries in 1990 to western Canada and Ontario are expected to increase, while United States and Quebec deliveries would decrease substantially.

Figure 5.2
Total IPL Deliveries
000 m^3/d



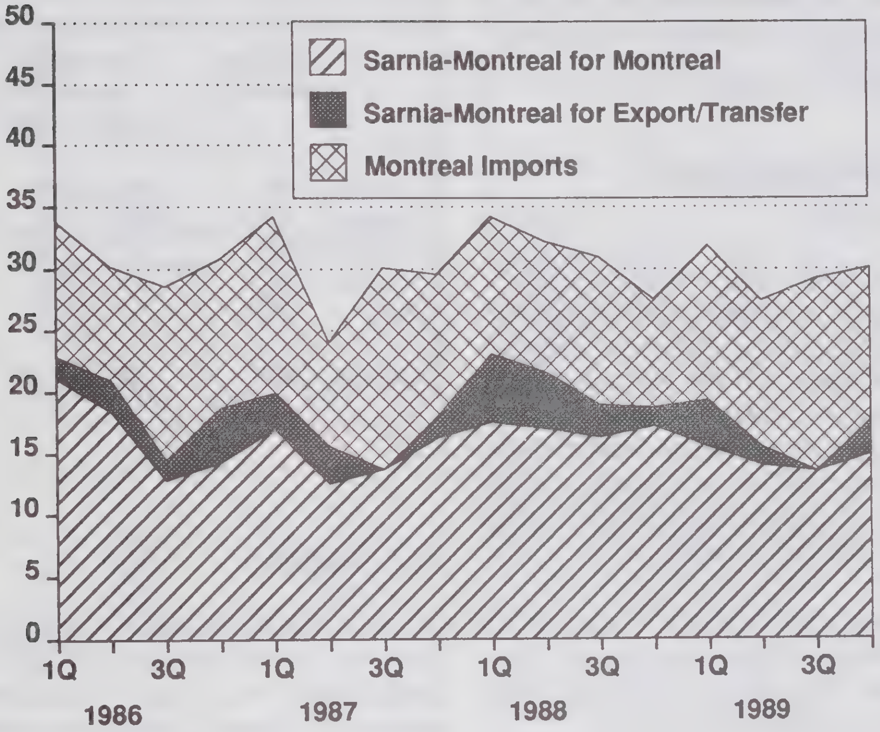
5.3 Pipelines to Montreal

Total deliveries of crude oil and equivalent to Montreal refiners, during the fourth quarter of 1989, averaged about 27 400 m^3/d, up 1 400 m^3/d from the same quarter a year earlier. Total domestic deliveries, via the Sarnia-Montreal portion of the IPL system, averaged 17 600 m^3/d, 1 100 m^3/d less than the year before; while foreign crudes, imported mainly through the Portland Pipe Line, increased by 3 700 m^3/d during the fourth quarter, to 12 500 m^3/d.

On an annual basis, receipts in Montreal were 27 800 m^3/d, almost unchanged from the year before. While IPL deliveries decreased, those from the Portland Pipeline increased by about 2 500 m^3/d to exceed 13 000 m^3/d.

Total IPL deliveries to Montreal were on average 16 500 m^3/d, suggesting a pipeline utilization rate for 1989 of about 32%, almost ten percentage points less than the previous year.

Figure 5.3
Deliveries to Montreal
000 m^3/d



6. Refinery Utilization and Stocks

- *Refinery utilization increased by 3% in 1989*
- *Crude oil and petroleum product stocks at the end of 1989 were virtually unchanged from a year earlier.*

6.1 Refinery Throughput and Utilization Rates

Refinery throughput differs from refinery crude oil receipts since feedstocks, other than crude oil, may also be charged in the refining process. Refinery throughput would also reflect changes in refinery feedstock inventories. Some of the "other" feedstocks include gas plant butane (used mostly by Prairie refineries) and partially processed oil (used mostly by B.C. refineries). In 1989, these "other" receipts approached 16 000 m^3/d, or about 6% of total feedstock receipts in Canada.

Table 6.1 shows regional refinery utilization rates during 1988 and 1989 as well as refinery capacity. Refinery utilization is calculated on a calendar day basis as opposed to an operational or stream day basis.

Table 6.1
Refinery Throughput
(Annual)

	Capacity (000 M^3/d)	Throughput (000 M^3/d)		Refinery Utilization %	
		1988	**1989**	**1988**	**1989**
Atlantic	55	46	46	84	84
Quebec	49	43	42	88	87
Ontario	96	77	83	80	86
Prairies	74	60	63	82	85
B.C.	26	24	23	92	90
Canada	**300**	**250**	**258**	**83**	**86**

6.2 Stocks

As illustrated in table 6.2.1, closing 1989 crude oil and petroleum product stocks totalled 13.9 million m^3, marginally higher than the same period last year. Petroleum product inventories, representing about 80% of total stocks, remained unchanged, while crude oil stocks increased by about 2%.

Table 6.2.1
Closing Crude and Product Inventories
(End December)
000 m^3/d

	Crude		Product		Total	
	1988	**1989**	**1988**	**1989**	**1988**	**1989**
CANADA	**2565**	**2616**	**11214**	**11281**	**13779**	**13897**
Atlantic	808	1213	1953	2074	2761	3287
Quebec	918	513	2299	2405	3217	2918
Ontario	508	564	3384	3292	3892	3856
Prairies	257	234	2379	2440	2636	2674
B.C.	74	92	1199	1070	1273	1162

Changes in the level of crude oil stocks were, for the most part, concentrated in the Atlantic and Quebec regions. End of December inventories in the Atlantic region, increased by about 50% compared with last year. In Quebec, refiners drew down stocks by 44%, reflecting the unusual shipping problems experienced near the end of the year.

Table 6.2.2
Closing Petroleum Product Inventories
(End December)

	000 m^3 1988	000 m^3 1989	Days * 1988	Days * 1989
All Products	11214	11281	54	50
"Main" Products	8077	8008	47	42
Motor Gasoline	3763	3952	48	47
Heating Oil	1611	1472	45	40
Diesel Oil	2051	1799	59	46
Heavy Fuel Oil	652	785	28	26

** Ratio of stocks to consumption*

Although the total level of refined product stocks remained unchanged from a year earlier, all regions recorded stock level adjustments. The Atlantic and Quebec regions recorded increases of 6% and 5% respectively, while petroleum product stocks in British Columbia fell by 10%.

Representing about 70% of total product stocks, inventories of "main" petroleum products increased slightly from 1988 as illustrated by table 6.2.2. Heavy fuel oil and motor gasoline were the only products to register increases. Stocks of petroleum products in the "other" products category, which includes products such as jet fuel, petrochemical feedstocks and asphalt, increased by about 5%.

Although the level of stocks increased in 1989 the number of days of supply diminished, reflecting higher levels of consumption.

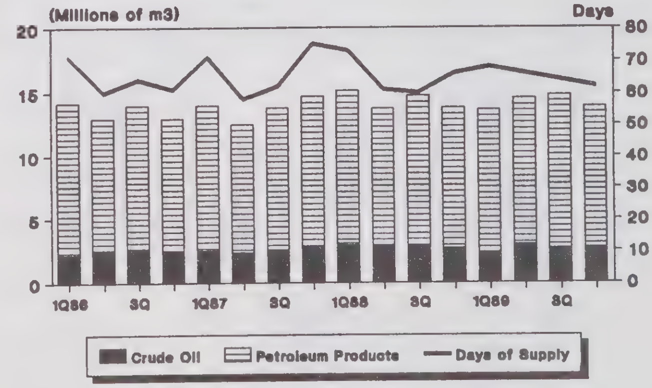
Table 6.2.3
Ratio of Stocks to Consumption
(End December)
Days

	Crude 1988	Crude 1989	Product 1988	Product 1989	Total 1988	Total 1989
Canada	12	12	54	50	66	62
Atlantic	24	73	57	56	88	89
Quebec	19	10	48	45	67	55
Ontario	7	7	49	43	56	50
Prairies	7	6	68	66	75	72
B.C.	4	3	55	45	59	48

By the end of 1989, the ratio of stocks to consumption for petroleum products and crude oil represented about 62 days of forward consumption, down 4 days from the close of the previous year.

The stocks above do not include estimates of crude oil held in pipeline tankage. If these stocks were included, the ratio of total stocks to consumption would increase by about 7 days to 69 days of forward consumption.

Figure 6.2.1
Closing Crude Oil and Product Inventories



Source: Statistics Canada

7. Energy Trade

- *Canada's energy trade surplus continued to fall in 1989 with over half the decline attributable to smaller surpluses in crude oil and refined products trade.*

7.1 International Trade

On a customs basis, energy commodities accounted for almost 10% of the total value of Canadian merchandise exports in 1989 and 5% of merchandise imports. As shown in the table below, Canada recorded an energy trade surplus of almost $6.4 billion last year. This surplus more than offset a $4.0 billion trade deficit in non-energy commodities.

Table 7.1
1989 Canadian Energy Trade (Annual)
$Cdn. (millions)

	Exports	Imports	Surplus
Crude Oil	4,410	3,668	742
Petroleum Products	1,786	1,682	105
Natural Gas	2,946	-	2,946
LPGs	527	74	453
Coal and Products	2,202	777	1,425
Electricity	659	297	362
Uranium	456	109	348
	12,986	6,606	6,380

By virtue of its economic size and proximity, the United States has historically been Canada's most important energy trading partner. In 1989, the U.S. accounted for over 80% of Canadian exports, and a third of Canadian imports. All exports of natural gas, LPGs and electricity were to the U.S., as were most oil and uranium exports. In fact, Canada enjoyed an energy trade surplus of $8.5 billion with the United States which more than offset the $2.1 billion energy deficit it incurred with the rest of the world.

In 1988, the energy trade surplus totalled $7.5 billion. The $1.1 billion decline in 1989 resulted from a 25% increase in the value of energy imports vis-a-vis only a marginally higher value of exports. Over half of the decline is attributable to smaller surpluses in crude oil and refined product trade.

The value of crude oil exports rose by 10% in 1989, despite the fact that volumetrically exports were down almost 10%. Export prices, however, were 20% higher. The United States accounted for almost 99% of the value of Canadian crude oil exports. With regard to crude oil imports, both their volume and price level rose in 1989, by 23% and 6%, respectively. The result was a 30% increase in their value. Although they were at twice the value recorded in 1988, American crudes still accounted for only 5% of total Canadian crude imports by value.

The value of refined product exports increased by 6% last year from the year before. Quantitatively, refined product exports were only marginally higher than in 1988, with most of the increase in value attributable to higher prices. Product imports on the other hand, rose 18% both in value and volumetrically, while prices remained virtually unchanged from 1988. Over 90% of product exports were destined to the U.S. which, in turn, supplied about 43% of Canada's refined product imports.

Figures 7.1.1 and 7.1.2 illustrate respectively Canada's energy trade position with the world in general, and with the United States specifically, over the last decade. The figures show that Canada ran an overall energy surplus throughout the 1980s. At the commodity level, Canada was in a deficit position in the early eighties with respect to crude oil trade. This was a period of relatively low domestic crude oil production and high refined product demand. Volumetrically crude oil imports were generally more than double exports during this period.

Figures 7.1.1
Energy Trade
All Countries
Cdn $ (Billions)

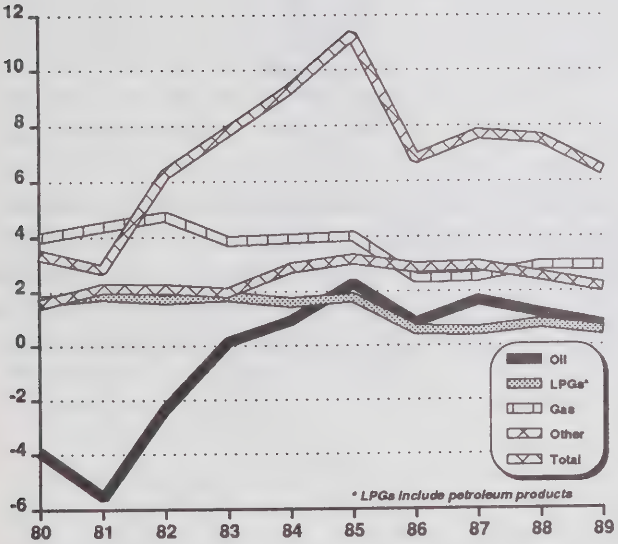
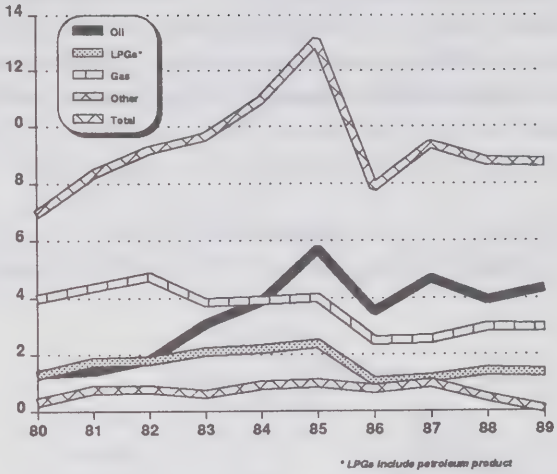


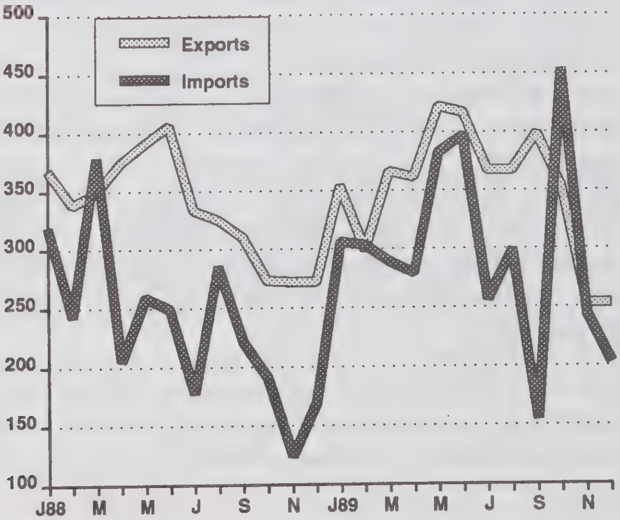
Figure 7.1.2
Energy Trade
U.S.A.
Cdn $ (Billions)



7.2 Review of Crude Oil Trade

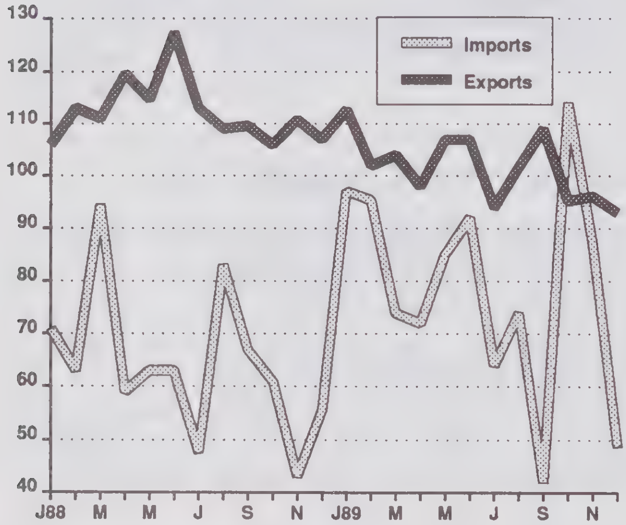
As illustrated in figure 7.2.1, Canada normally enjoyed a surplus in crude oil trade over the 1988-89 period, with the value of its crude oil exports usually exceeding that of its imports. Nevertheless, the figure also shows that the monthly surpluses were generally smaller in 1989. (As these are Customs based trade figures they overstate crude oil imports for Canadian needs to the extent of the processing agreements some Atlantic refiners have.)

Figure 7.2.1
Value of Crude Oil Imports and Exports
Cdn $ (Millions)



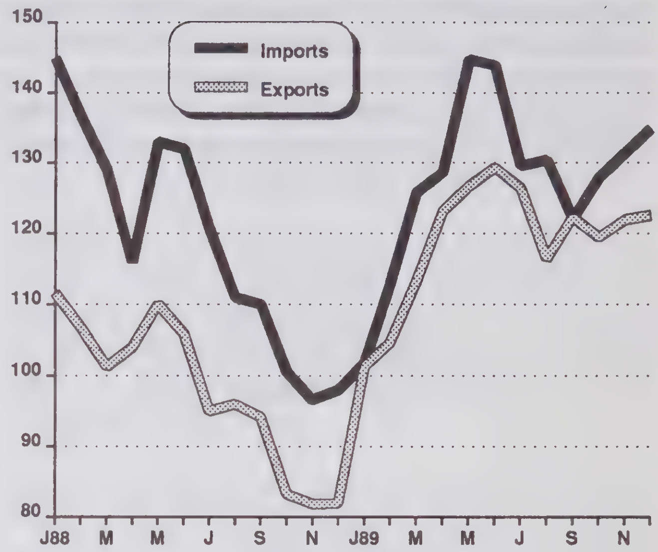
The deterioration in the trade surplus resulted from a downward trend in the volume of exports over the last two years, combined with a pronounced upward shift in the volume of imports at the beginning of 1989. Figure 7.2.2 illustrates the convergence of imports and exports. Declining exports and higher imports in turn reflected falling Canadian crude oil production on the one hand, and strong domestic demand for refined products, on the other.

Figure 7.2.2
Crude Oil Import and Export Volumes
(000 m^3/d)



The third figure shows the trends in Canadian crude oil export and import prices. Export prices are lower because Canada is proportionately a large exporter of heavy crude and importer of light crude. As Canada remained a net crude oil exporter, the rise in the world price of crude oil in 1989 favoured Canada's crude oil trade position. In fact, had monthly export and import prices during 1989 remained at the levels recorded during the corresponding periods the previous year, last year's cumulative crude oil surplus would have been virtually eliminated.

Figure 7.2.3
Crude Oil Import and Export Prices
Cdn $/$m^3$



A convergence in export and import prices also mitigated the decline in the crude oil trade surplus. This convergence related to both a higher ratio of light to heavy crude exports last year; and the tight supply situation for light sweet crude oil in the U.S. midwest during much of 1989.

8. Crude Oil and Product Prices

- *High world demand combined with a series of accidents that adversely affected crude oil supply resulted in higher and more stable crude oil prices in 1989.*

- *The differential between Canadian and international crude oil prices narrowed last year.*

8.1 International Crude Oil Prices

In 1989, spot prices for West Texas Intermediate (WTI) crude oil, at Cushing, averaged $19.60/bbl, its highest yearly level since 1985. Unforeseen events, such as North Sea and Alaskan production accidents and severe weather conditions, combined with stronger-than-expected world oil demand, helped keep oil markets in relative supply/demand balance throughout the year.

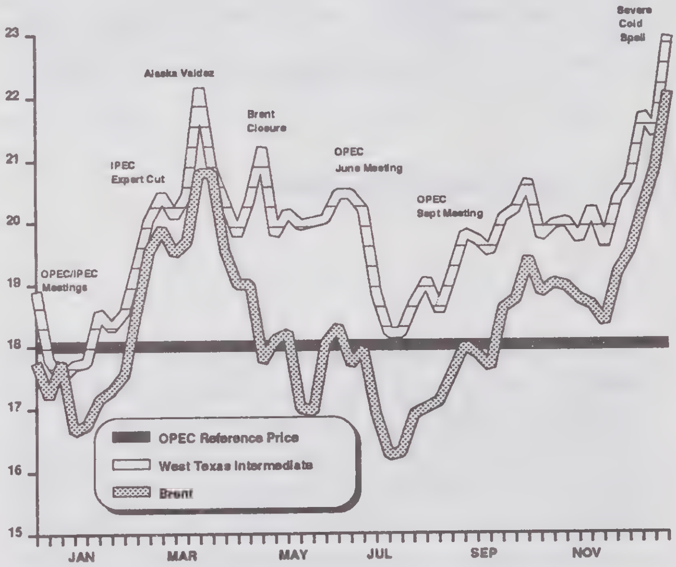
In response to these market conditions, OPEC raised its production ceiling twice in 1989. First, at the June ministerial conference, OPEC raised its ceiling by 1.0 MMB/D, to 19.5 MMB/D for the third quarter and then in September, to 20.5 MMB/D for the fourth quarter. On each occasion, production was shared on a pro rata basis, a system to which Kuwait and the UAE strenuously objected. While both members continued to exceed quotas, oil markets were able to absorb this excess output without driving down crude oil prices.

By the fourth quarter of 1989, the market expected stable crude oil prices on the assumption that excess OPEC crude oil production would be offset by higher winter demand. WTI was averaging above $20/bbl and U.K. Brent above $19/bbl. At OPEC's conference in November, the organization raised its production ceiling to 22 MMB/D for the first half of 1990. Kuwait's demands for a higher production share were met with a sizeable increase in quota to 1.5 MMB/D. In contrast, the UAE was assigned its previous quota of 1.1 MMB/D. As a result, the UAE indicated that it would continue to produce in the 2.0 MMB/D range, in effect, raising expected OPEC crude output to around 23 MMB/D, a level considered to be above what the market would bear. However, a severe December cold spell in North America benefitted OPEC by absorbing excess supplies and firming crude oil prices. WTI averaged over $21/bbl in December and closed the year at $22/bbl.

The call on OPEC crude oil, in early 1990, is expected to fall to 21 MMB/D or less, as markets enter a period of normal seasonal decline. Thus OPEC crude oil production may well exceed actual demand in the first and second quarters of 1990, resulting in lower crude oil prices. However, crude oil prices may firm over the second half of 1990 as demand for OPEC crude increases. Assuming OPEC maintains some semblance of production restraint, WTI is expected by most analysts to range between $18 and $20/bbl over the next year.

Figure 8.1 illustrates the strengthening of spot crude oil prices over 1989.

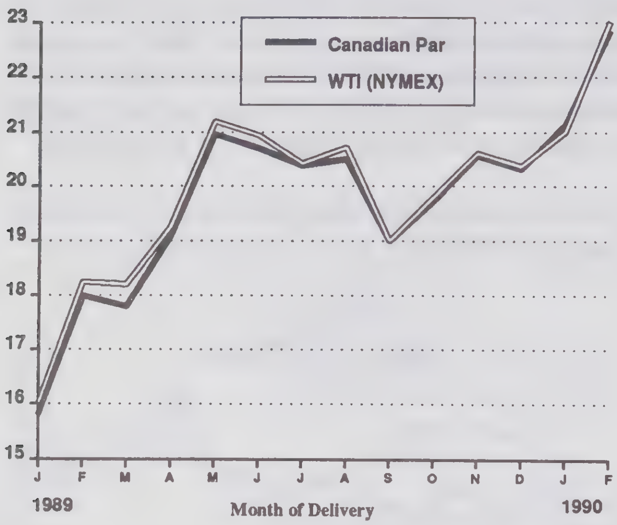
Figure 8.1
Crude Oil Prices
US$/bbl



8.2 Domestic Crude Oil Prices

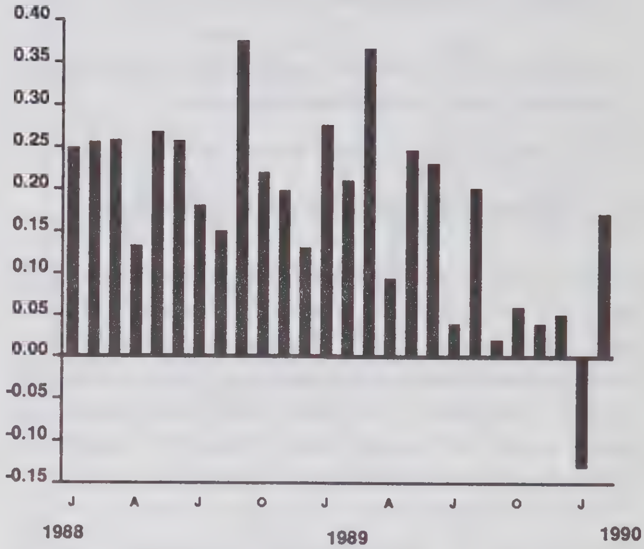
During the fourth quarter of 1989, Canadian Par crude oil (the Canadian benchmark crude at 40°API, 0.5%S) posted prices averaged $22.79/bbl, an increase of $0.80/bbl over the third quarter of 1989. The increase can be attributed to a combination of an international oil price increase (about $1.00/bbl), a strengthening of the Canada-U.S. exchange rate which effectively reduced prices about $0.30/bbl, and the narrowing of the differential between Canadian and U.S. crude oil prices ($0.11/bbl).

Figure 8.2.1
Canadian Par Crude vs WTI(NYMEX)*
at Chicago
US$/bbl



** New York Mercantile Exchange*

Figure 8.2.2
Canadian Par vs WTI(NYMEX)
Differential at Chicago
US$/bbl



Notes:
Average 1988 - US$ 0.22/bbl
Average 1st Half 1989 - US$ 0.24/bbl
Average 4Q 1989 - US$ -0.02/bbl

The differential between Canadian Par and WTI NYMEX prices, on a delivered basis in Chicago, is illustrated in figure 8.2.2. The average differential in the fourth quarter of 1989 was US$0.02/bbl in favour of Canadian Par, compared to an average of US$0.09/bbl for the third quarter in favour of WTI. The reduction in the differential in part reflects the tightening of light sweet crude oil supplies in the North American market as well as the absence of pipeline constraints on the delivery of crude oil (no IPL apportionment).

Figure 8.2.3 compares actual prices for Alberta light and heavy crude oil, purchased for use in Canada at the main trunk line injection stations. On average, reported light conventional crude oil quality during the fourth quarter of 1989 was 37.5°API, 0.39% sulphur, and blends of heavy crude were 24.4°API, 2.53% sulphur. The differential between Canadian light and heavy crude oil prices, during the fourth quarter of 1989 was about $4.56/bbl, $0.48/bbl higher than the third quarter differential, reflecting the normal seasonal change in demand for heavy crude oil.

Figure 8.2.3
Comparison of Domestic Light and Heavy Crude
(Actual Purchase Prices - Alberta)
Cdn$/bbl

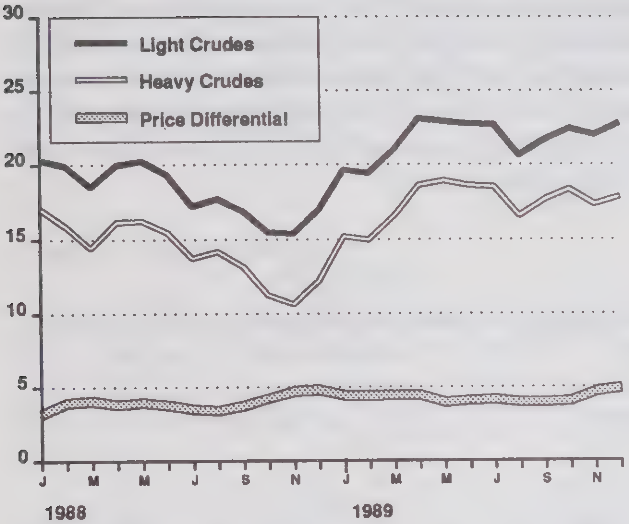
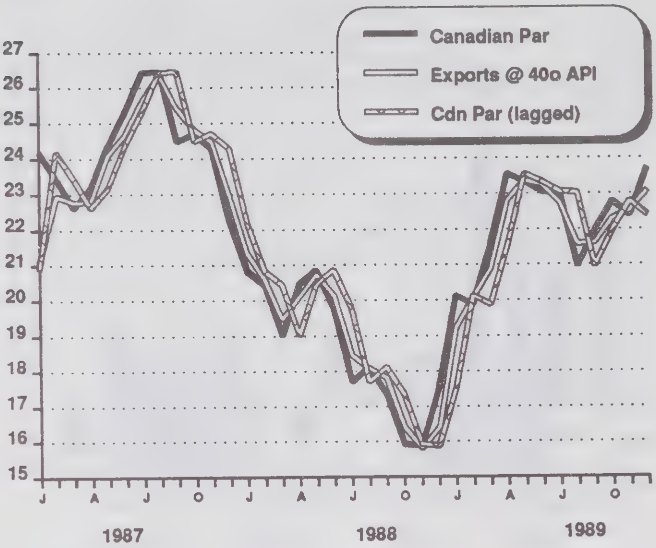


Figure 8.3.1
Light Crude Exports vs Canadian Par
Cdn$/bbl



8.3 Export Prices

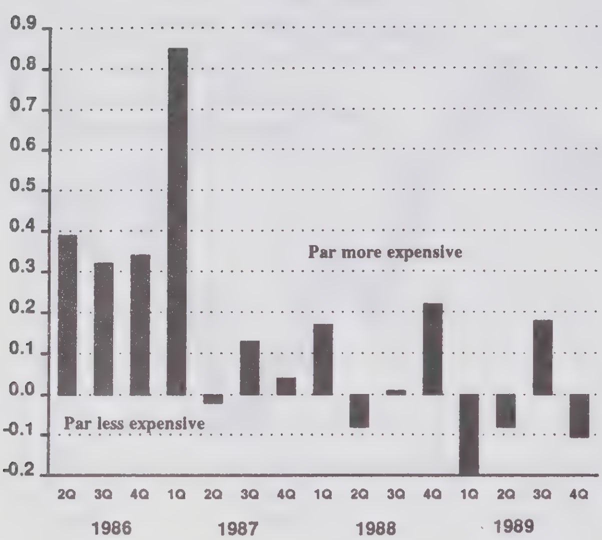
Figures 8.3.1 and 8.3.2 illustrate the relationship between light crude oil export prices and domestic prices.

Prices of light crude oil exported to the United States via the IPL system were netted back to Edmonton and adjusted to 40°API, on a stream by stream basis. These prices were then compared to Canadian Par crude prices, also at Edmonton.

As can be observed in figure 8.3.1, in a period of declining prices, exports would appear to be more expensive than Par crude (the solid black line on the graph) for the same month; and, in a period of increasing prices, exports would appear to be cheaper. A comparison on that basis alone is however misleading as it fails to consider time lags. Canadian Par crude prices were therefore "lagged" one month to provide a range within which export prices can be expected to fall.

For comparison purposes, an average of the current month's Par crude and its lagged price was calculated. Figure 8.3.2 illustrates the differential between this composite average Par crude and the average export price. The contraction of the differential follows the general narrowing of the differential between Canadian and international crude oil prices.

Figure 8.3.2
Differential
Exports vs Canadian Par
Cdn$/bbl



8.4 Petroleum Product Prices

Price Trends

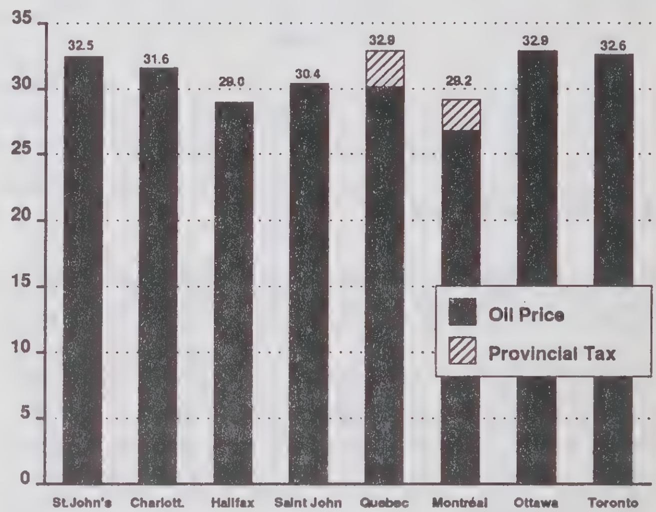
The average price for regular unleaded gasoline in Canada (self-serve outlets) increased 4.5 cents per litre, or 9.5% in 1989 (December 26, 1989 vs December 27, 1988). During the year average crude costs increased 4.3 cents per litre; federal taxes, 1.1 cents per litre; and average provincial taxes, 0.8 cents per litre. The combined crude price and tax increases, totalling 6.2 cents per litre, were not fully covered by the average retail price increase.

During 1989, prices increased in all of the ten cities surveyed. The increases ranged from 1.3 cents per litre in Toronto to 11.1 cents per litre in Calgary. Price wars prevailed in several Prairie cities during the first half of 1989. (Appendix II)

Retail diesel prices increased an average 4.2 cents per litre during 1989. Increases, which were recorded in each of the ten cities, ranged from 0.5 cents per litre in Winnipeg to 6.6 cents per litre in Calgary.

By the end of December 1989, heating oil prices were beginning to increase in response to tight supplies resulting from unseasonably cold weather in November and December, maintenance at some Quebec refineries, transportation delays resulting from a labour dispute with Coast Guard employees and supply shortages in the eastern United States. The average price was 31 cents per litre, 2.3 cents per litre higher than in December 1988. During the year, prices increased in nine of the ten centres surveyed. The increases ranged from 0.8 cents per litre in Winnipeg to 7 cents per litre in Calgary, a city where little heating oil is used.

Figure 8.4.1
Average Consumer Furnace Oil Prices
(December 1989)
Cdn¢/litre



Consumption Taxes on Petroleum Products

Federal sales and excise taxes increased during the year. The sales tax rate increased from 12% to 13.5% on June 1, 1989, resulting in an increase of about 0.4 cents per litre on gasoline and 0.3 cents per litre on diesel. On April 28, 1989, the excise tax on gasoline was increased 1 cent per litre and a surcharge of 1 cent per litre was imposed on leaded gasoline to discourage misfuelling. The excise tax on diesel was not changed. (Appendix III)

Newfoundland increased its ad valorem rate to 23% on gasoline, and 27% on diesel. The province also imposed a 1.5 cent per litre surcharge on leaded gasoline. New Brunswick changed its ad valorem rates from 20% to 24.5% on gasoline and from 23% to 31.5% on diesel and introduced a 2.2 cent per litre surcharge on leaded gasoline. In Saskatchewan, the fixed rate tax was increased 3 cents per litre on gasoline with a surcharge of 2 cents per litre on leaded gasoline. All but four provinces, Nova Scotia, Prince Edward Island, Quebec and Alberta, now levy a surcharge on leaded gasoline.

Canada vs United States

During 1989, the average retail price for all grades of motor gasoline increased more in Canada than in the United States. At the end of 1989, the differential had risen to 21 cents per litre from 16.3 cents per litre at the end of 1988.

Higher taxes in Canada accounted for two-thirds of the differential in December 1989, down from 74% in December 1988. The balance of the differential is attributable to higher refining and marketing costs and/or profits in Canada, and to the strengthening of the Canadian dollar.

Figure 8.4.2
Average Retail Price of Motor Gasoline
(Canada vs United States)
Cdn¢/litre

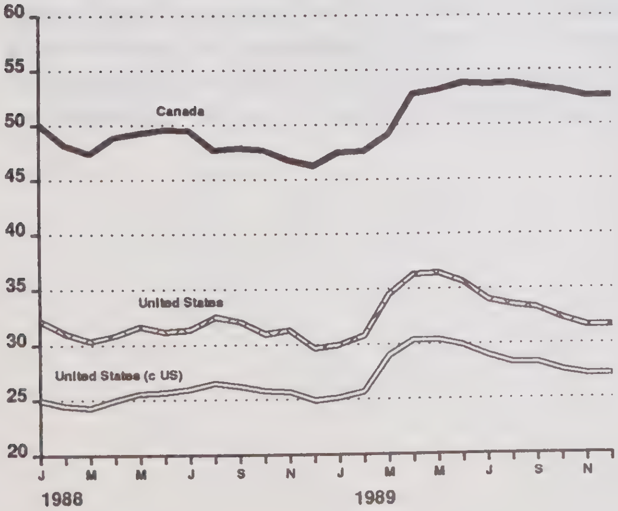
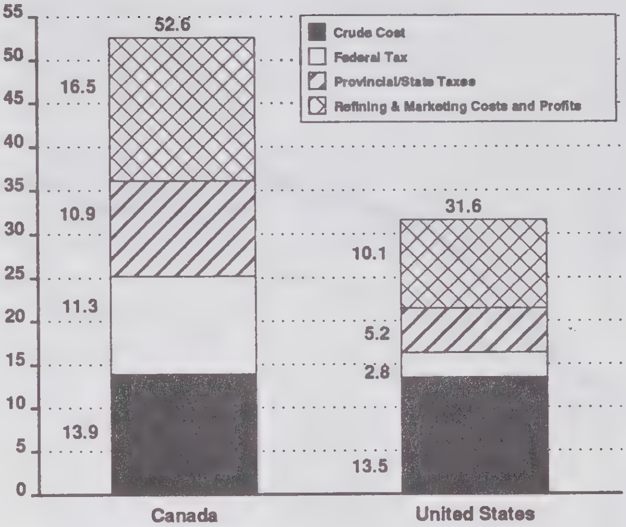


Figure 8.4.3
Breakdown of Average Pump Price
(December 1989)
Cdn¢/litre



Exchange Rate = 1.1612

8.5 Gasoline Prices - A 10-Year Review

Price Trends

Gasoline prices increased 28¢/l during the 1980s. Figure 8.5.1 illustrates the annual average price for regular leaded gasoline in 10 major centres across Canada and indicates the impact of tax increases on retail prices between 1979 and 1989. Between 1979 and 1985, the average retail price of regular leaded gasoline increased from 21.9¢/l to 50.7¢/l, or almost 15% per year. The rise in Canadian crude prices, higher consumption taxes, a depreciating exchange rate and special consumer charges to finance various programs under the regulated regime, all contributed to the rise in prices during the first half of the decade.

In contrast to the first half of the decade, virtually all of the gasoline price increase in the last half of the 1980s has been the result of consumption tax increases. Although the 1989 Canada average price, excluding tax, is more than 10¢/l lower than the 1985 average, the retail pump price is only 0.9¢/l lower.

Figure 8.5.1
Canada Average Regular Leaded Gasoline Prices at Full-Serve
Cdn¢/litre

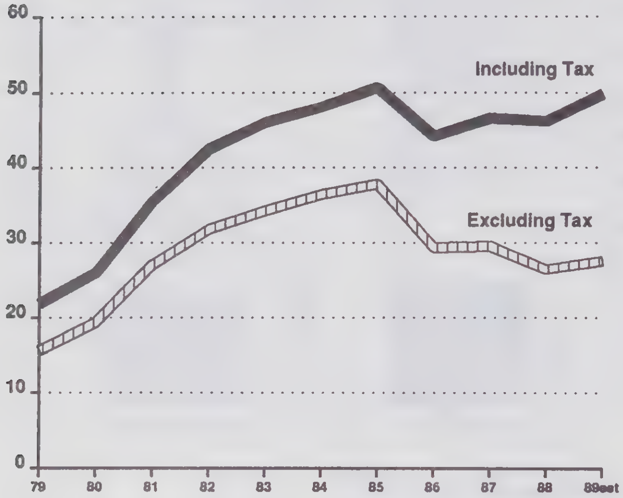
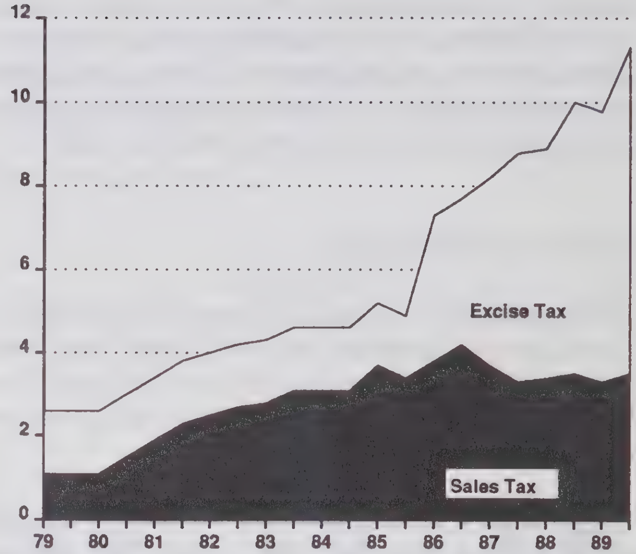


Figure 8.5.2
Federal Sales and Excise Taxes on Motor Gasoline
(January and July)
Cdn¢/litre



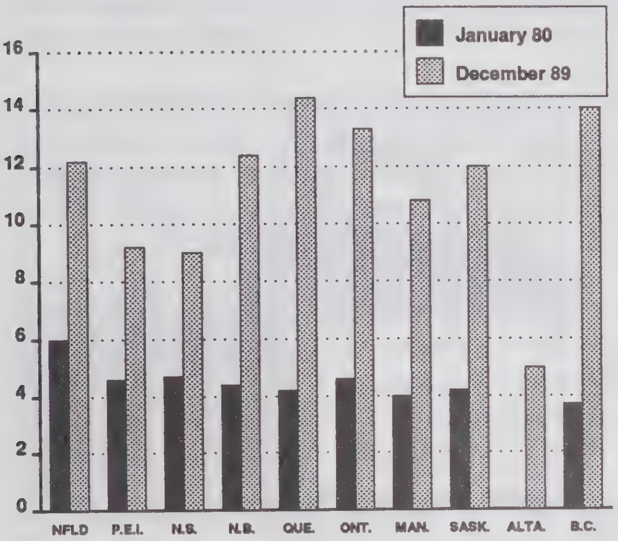
Consumption Taxes

Increases in government consumption taxes accounted for nearly 60% of the gasoline price increase over the decade.

Federal taxes on gasoline are made up of a sales tax, based on an ad valorem rate, and an excise tax which is not tied to the price of the product. As illustrated in Figure 8.5.2, average federal taxes increased steadily through the first half of the decade, doubling in five years from 2.6¢ to 5.2¢/l. During the second half they more than doubled again to 11.3¢/l. The sales tax reached its peak in 1986 with lower gasoline prices in the latter part of the decade contributing to a reduction in this tax. The average excise tax was constant during the first half of the 1980s and increased from 1.5¢ to 7.8¢/l during the last four years.

Taxes also increased in all provinces during the decade (Figure 8.5.3). Average provincial taxes more than doubled to over 10¢/l by 1989. In Quebec and British Columbia road taxes tripled. Some provinces moved from ad valorem to fixed rates in an attempt to stem revenue losses from falling gasoline prices. Other provinces increased their ad valorem rates to make up the difference. In 1982 Saskatchewan dropped its tax on gasoline but re-introduced it in 1987, at about the same time as Alberta re-introduced its petroleum product tax.

Figure 8.5.3
Provincial Taxes on Regular Leaded Gasoline
Cdn¢/litre

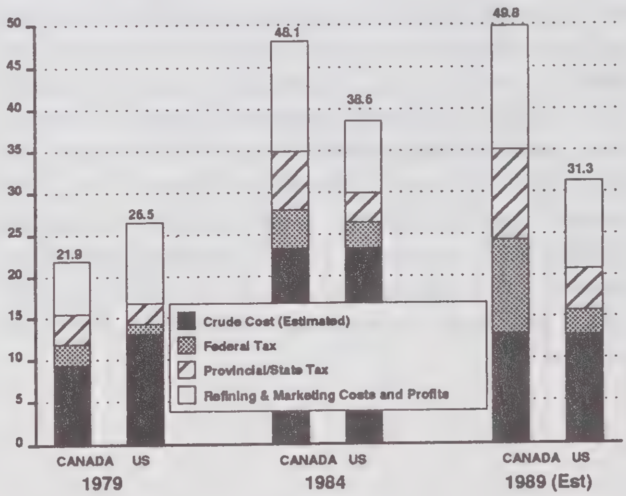


There was no grade differential in provincial taxes at the beginning of the decade. Prompted by environmental concerns, six provinces, as well as the federal government, now impose a surcharge on leaded gasoline to discourage its use.

Canada vs United States

Canadian gasoline prices were lower than U.S. prices (¢Cdn/l) in 1979. By 1989, however, the average Canadian price exceeded the U.S. price by 60%. As indicated in Figure 8.5.4, consumption taxes have been the single largest contributor to higher gasoline prices in Canada since 1979. Higher consumption taxes account for more than 75% of the differential in gasoline prices between Canada and the United States. Between 1979 and 1989 Canadian taxes increased by 16.0¢/l while U.S. gasoline taxes rose by 4.3¢Cdn/l. In 1989, the gap between Canadian and U.S. prices was the widest of the decade.

Figure 8.5.4
Pump Price Components for Regular Leaded Gasoline
Canada vs United States
Cdn¢/litre



9. Capital and Repair Expenditures (*)

- *Capital and repair expenditures in the oil and gas industry are expected to rise by almost 20% in 1990.*

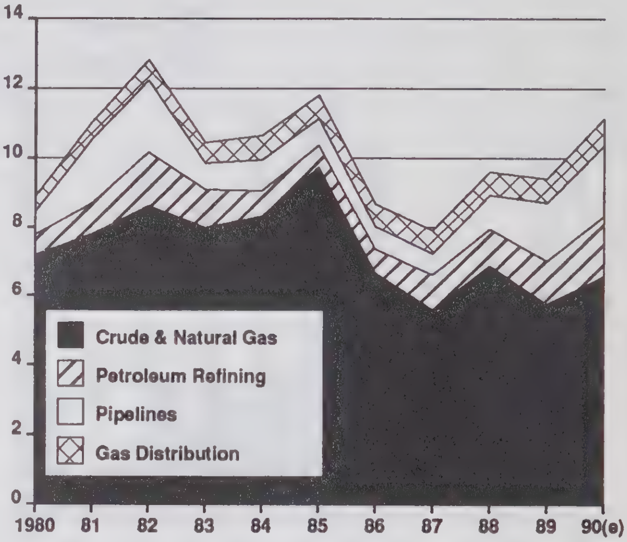
- *Since 1987 the industry has accounted for about 6% of total capital and repair expenditures in Canada.*

A survey recently completed by Statistics Canada suggests that capital and repair expenditures in the energy sector (excluding coal and uranium mining) should exceed $23 billion in 1990. The electric power industry will likely account for over half of these expenditures (i.e. for about $12 billion) with the oil and gas industry making up the balance.

The figure below illustrates the trends in capital and repair expenditures by sub-sector in the oil and gas industry since 1980. Expenditures in the upstream sector rose in tandem with petroleum prices and revenues during the first half of the decade, peaking in 1985 before declining abruptly in 1986 following a sharp drop in world crude oil prices. Expenditures recovered somewhat in 1988, in part reflecting the stimulative effect of government drilling incentives and the completion of Syncrude's Capacity Expansion Program. By 1989 however, capital spending in the upstream sector had resumed its downward course following some of the lowest crude oil prices seen in the decade towards the end of 1988, and the termination of certain drilling incentives.

(*) *Capital expenditures include the cost of procuring, constructing and installing new durable plant and machinery, whether for replacement of worn or obsolete assets, or as net additions to existing assets. Repair expenditures represent the non-capitalized outlays made to maintain the operating efficiency of the existing stock of durable assets.*

Figure 9.1
Capital and Repair Expenditures in the Oil and Gas Industry
Cdn $ (Billions)



The outlook for 1990 is for capital expenditures to approach $6.6 billion in the upstream sector, a rise of 15%, or more than $800 million, over the 1989 level. The conventional sector should account for most of the increase, reflecting the positive impact of last year's higher and steadier crude oil prices on this year's exploration and development intentions; and the growing demand for natural gas, particularly in the export market. In addition to a 10% to 15% increase in drilling expenditures, the conventional sector is planning significant spending increases in enhanced recovery projects, production facilities and natural gas processing plants in 1990.

In the non-conventional sector, which is comprised mainly of synthetic and bitumen operations, capital spending is expected to increase by about 20% to $460 million from last year. Nevertheless, this is only about half the annual levels recorded between 1985 and 1988, a period of relatively intense bitumen development.

In the downstream sector (petroleum upgrading and refining), expenditures are expected to rise by over 35% to $1.7 billion. Part of this spending is expected to go towards the $1.3 billion Husky Upgrader, currently under construction and scheduled for completion in 1992. Refineries will also be upgrading their facilities to meet more stringent product specifications in response to environmental legislation.

Pipeline expenditures should surpass $2 billion in 1990, an increase of almost 20% over the previous year. Most of these expenditures will be used to finance the expansion of the natural gas pipeline system, especially that part serving the export market.

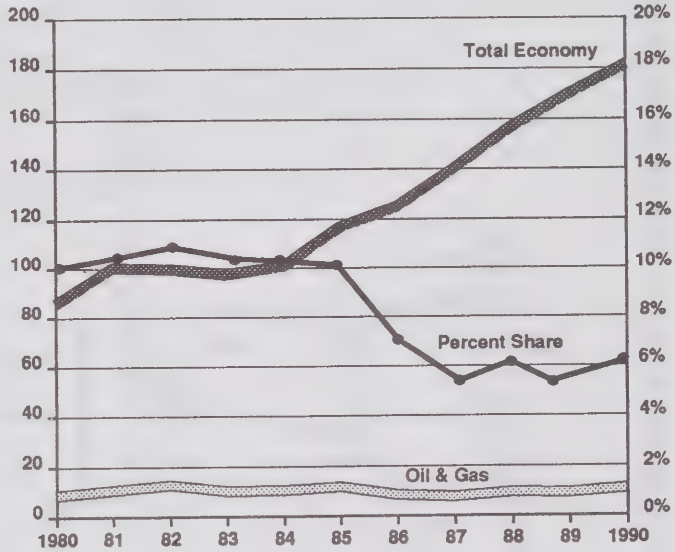
Reflecting a steadily rising number of new customers, natural gas marketers in 1990 intend to spend close to $800 million on expanding and maintaining their urban gas distribution networks. This would represent an increase in expenditure of almost 15% from 1989.

In the first half of the 1980s, the oil and gas industry consistently accounted for over 10% of total capital and repair expenditures in the economy (see figure below). In the latter part of the decade its share fell as economic growth was stronger in other sectors of the economy. Since 1987, the industry has accounted for about 6% of the total.

Figure 9.2

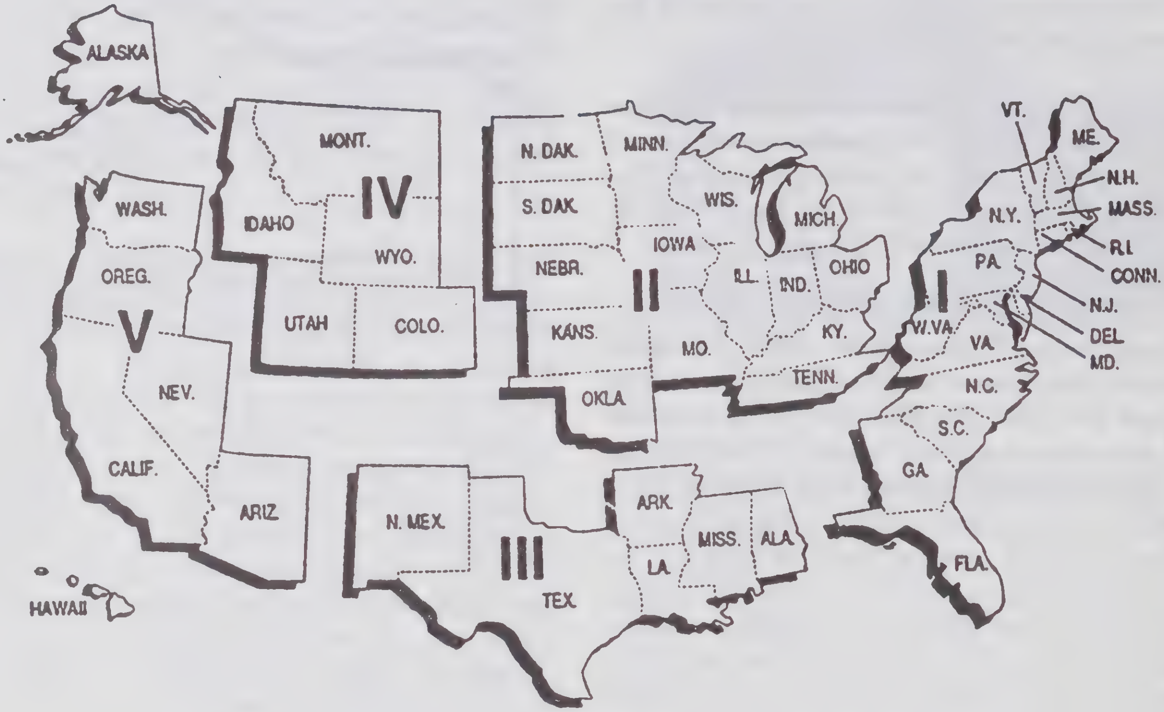
Capital and Repair Expenditures Oil and Gas vs. Total Economy

Cdn $(Billions)



Appendix I

U.S. Petroleum Administration for Defense (PAD) Districts



Appendix II
Average Regular Unleaded Gasoline Prices
Self-Serve
1988-1989

	1988 Dec. 27	1989 March 28	1989 June 27	1989 Sept. 26	1989 Dec. 26	% Change 12 mo.
	cents per litre					
St. John's NFLD	50.9	52.2	56.3	56.7	56.8	11.6
Charlottetown	49.6	49.6	51.5	54.1	53.8	8.5
Halifax *	47.9	48.8	52.4	52.4	52.4	9.4
St. John N.B.*	48.6	50.2	53.3	53.9	51.9	6.8
Montreal	54.0	55.0	58.1	58.1	58.1	7.6
Toronto	45.9	48.5	50.1	51.3	47.2	2.8
Winnipeg	44.5	43.9	50.9	51.4	50.7	13.9
Regina	39.2	43.3	53.9	53.8	45.8	16.8
Calgary	37.0	41.4	48.2	48.1	48.1	30.0
Vancouver	47.3	49.5	53.6	54.1	54.9	16.1
Canadian Avg.	47.6	49.5	53.1	53.6	52.1	9.5
Consumption taxes included:						
Federal	9.9	9.8	11.1	11.0	11.0	11.1
Provincial	9.8	9.8	10.4	10.5	10.6	8.2

* *Full-serve*

Appendix III

Consumption Taxes on Petroleum Products

(December 1, 1989)

	Ad valorem		Gasoline			
	Mogas	**Diesel**	**Reg L**	**Reg UL**	**Prem UL**	**Diesel**
	(%)		(cents per litre)			
FEDERAL TAXES						
Sales			3.47	3.47	3.58	2.69*
Excise			8.5	7.5	7.5	4.0
PROVINCIAL TAXES						
Newfoundland [a]	23[b]	27	12.2	10.7	10.7	12.3
Prince Edward Island	20	23	9.2*	9.2*	9.2*	9.4*
Nova Scotia	20	21	9.0	9.0	9.0	8.8
New Brunswick	24.5[c]	31.5	12.4	10.4	11.0*	11.1*
Quebec [d]			14.4	14.4	14.4	12.45
Ontario			13.3	10.3	10.3	10.9
Manitoba			10.8	9.0	9.0	9.9
Saskatchewan			12.0	10.0	10.0	10.0
Alberta			5.0	5.0	5.0	5.0
British Columbia[c]	22.5[f]		11.01*	9.01*	9.01*	9.45*
Yukon			4.2	4.2	4.2	5.2
Northwest Territories	17	(g)	8.5*	8.5*	8.5*	7.2*

(a) *The gasoline tax is reduced by 1.5 cents per litre in the region between the Quebec border and Red Bay in Labrador.*

(b) *This applies to unleaded gasoline. The tax on leaded gasoline is 1.5 cents per litre higher than the unleaded tax.*

(c) *This applies to all gasolines. There is also a 2.2 cent per litre surcharge on regular leaded gasoline.*

(d) *Reduced by varying amounts in certain remote areas and within 20 kilometers of the provincial and U.S. borders.*

(e) *Additional transit tax of 3.0 cents per litre in Vancouver.*

(f) *This applies to unleaded gasoline. Taxes on leaded gasoline and diesel fuel 2.0 and 0.44 cents per litre higher, respectively, than the unleaded tax.*

(g) *85% of gasoline tax.*

** Changed since last quarter.*

Glossary

Bitumen	A naturally occurring viscous mixture composed mainly of hydrocarbons heavier than pentane, which may contain sulphur compounds and which in its natural state is not recoverable at a commercial rate through a well.
Consumption	Petroleum product consumption based on net sales of products; it excludes oil consumption by the refineries.
Conventional area	Those areas of Canada that have a long history of hydrocarbon production. Conventional areas are also referred to as nonfrontier areas.
Crude oil	Includes crude oil, synthetic crude, oil produced from oil sands plants, and condensate.
Feedstock	Raw material supplied to a refinery or petrochemical plant.
Heavy crude oil	Loosely applied, crude oils with a low API gravity (high density).
In situ recovery	With reference to oil sands deposits, the use of techniques to recover bitumen without the necessity of mining the sands.
Light crude oil	Crude oil with a high API gravity (low density). Generally includes all crude oil and equivalent hydrocarbons not included under heavy crude oil.
NGLs	Those hydrocarbon components recovered from raw natural gas as liquids by processing through extraction plants, or recovered from field separations, scrubbers or other gathering facilities. Includes the hydrocarbon components ethane, propane, butane and pentanes plus, or a combination thereof.
Oil sands	Deposits of sands and other rock aggregate that contain bitumen.
Pentanes plus	Also referred to as condensate. A volatile hydrocarbon liquid composed primarily of pentanes and heavier hydrocarbons. Generally a by-product obtained from the production and processing of natural gas.
Productive capacity	The estimated production level that could be achieved, unrestricted by demand, but restricted by reservoir performance, well density and well capacity, oil sands mining capacity, field processing and pipeline capacity.
Shut-in	The unused productive capacity of currently producing oil and gas wells.
Synthetic crude oil	Crude oil produced by treatment in oil upgrading facilities designed to reduce the viscosity and sulphur content.